British Columbia Utilities Commission

2002/03 Annual Service Plan Report

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BRITISH COLUMBIA UTILITIES COMMISSION

British Columbia Utilities Commission

2002/03 Annual Service Plan Report

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Vancouver, BC
August 2003

To the Lieutenant Governor in Council

MAY IT PLEASE YOUR HONOUR:

Pursuant to the Utilities Commission Act and the Budget Transparency and Accountability Act, I respectfully submit this Report on the activities of the British Columbia Utilities Commission for the fiscal year 2002/03.

Section 13 of the Utilities Commission Act requires the Commission to submit a report to the Lieutenant Governor in Council for the preceding fiscal year, setting out briefly all applications and complaints, summarizing Commission findings, and reporting on other matters considered in the public interest. The Act was recently amended to move from calendar year to fiscal year reporting, consistent with the Budget Transparency and Accountability Act reporting timeframe.

This Annual Report also serves to report on the first year of the BC Utilities Commission's Service Plan for the period 2002/03 through 2004/05, dated January 30, 2002.

Peter Ostergaard

PETER OSTERGAARD
Chair

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Standard Abbreviations & Acronyms

Utility/Applicant

Aquila Networks Canada (British Columbia) Ltd.[1]	Aquila
BC Gas Utility Ltd. (subsidiary of BC Gas Inc.)[2]	BC Gas
British Columbia Hydro and Power Authority	BC Hydro
Centra Gas British Columbia Inc.[2]	Centra Gas, Centra
Centra Gas Whistler Inc.[2]	Centra Whistler
Central Heat Distribution Limited	CHDL
Hemlock Valley Electrical Services Limited	HVES
Pacific Northern Gas Ltd.	PNG, PNG-West
Pacific Northern Gas (N.E.) Ltd.	PNG (N.E.)
Plateau Pipe Line Ltd.	Plateau
Port Alice Gas Inc.	Port Alice Gas
Princeton Light and Power Company, Limited	PLP
Squamish Gas Co. Ltd.[2]	Squamish Gas
Silversmith Light & Power Corporation	Silversmith
Stargas Utilities Ltd.	Stargas
Sun Peaks Utilities Co., Ltd.	Sun Peaks
Sun Rivers Services Corp.[3]	Sun Rivers
The Corporation of the City of Nelson	City of Nelson
Terasen Gas Inc. (subsidiary of Terasen Inc.)	Terasen, Terasen Gas, TGI
Terasen Gas (Whistler) Inc.	Terasen Whistler
Terasen Gas (Vancouver Island) Inc.	Terasen VI, TGVI
Terasen Gas (Squamish) Inc.	Terasen Squamish
Terasen Multi-Utility Services Inc.	Terasen MUS
Trans Mountain Enterprises of British Columbia Limited	TME
Westcoast Energy Inc.	WEI, Westcoast
UtiliCorp Networks Canada (British Columbia) Ltd.[1]	UNC, UtiliCorp
The Yukon Electrical Company Limited	YECL

Other

Agent Billing and Collection for Transportation Service	ABC-T
Allowance for Funds Used During Construction	AFUDC
Alternative Dispute Resolution	ADR
Apartment Customer Rates	ACR
Certificate of Public Convenience and Necessity	CPCN
Energy for our Future: A Plan for BC	Energy Plan or Energy Policy
Gas Cost Reconciliation Account	GCRA
Gas Cost Variance Account	GCVA
Independent Power Producers	IPPs
Large General Service	LGS
Natural Gas Vehicles	NGV
Return on Common Equity	ROE
Small General Service	SGS
Utilities Commission Act	the Act, UCA

1 On May 10, 2002 UtiliCorp Networks Canada (British Columbia) Ltd. changed its name to Aquila Networks Canada (British Columbia) Ltd.

2 On April 25, 2003 BC Gas, Centra Gas, Centra Whistler and Squamish Gas changed their names to Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., and Terasen Gas (Squamish) Inc.

3 On April 25, 2003 Sun Rivers Services Corp. changed its name to Terasen Multi-Utility Services Inc.

Organizational Overview

Introduction

The British Columbia Utilities Commission ("the Commission", "BCUC") is a regulatory agency of the Provincial Government, operating under and administering the *Utilities Commission Act* ("UCA", "the Act"). The Commission is responsible for ensuring that customers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities it regulates, that shareholders of these utilities are afforded a reasonable opportunity to earn a fair return on their invested capital, and that the competitive interests of BC businesses are not frustrated. It approves the construction of new facilities planned by utilities and their issuance of securities. The Commission's function is quasi-judicial and it has the power to make legally binding rulings. Decisions and Orders of the Commission may be appealed to the Court of Appeal on questions of law or jurisdiction.

The Commission also reviews energy-related matters referred to it by Cabinet. These inquiries usually involve public hearings, followed by a report and recommendations to Cabinet. In addition, under Part 7 of the *Pipeline Act*, the Commission establishes tolls and conditions of service for intraprovincial oil pipelines. The Commission also has responsibilities under the UCA for electricity transmission facilities and energy supply contracts, matters that are likely to become more active as the reorganization of the energy industry proceeds.

The Commission has been self-funded since 1988. Its costs are recovered primarily through a levy on the public utilities it regulates.

The Act provides for a Chair, one or more Deputy Chairs, up to seven Commissioners (including the Chair and Deputy Chair[s]), and temporary Commissioners. All are appointed by the Lieutenant Governor in Council. As of March 31, 2003, there were four temporary Commissioners, one full-time Commissioner and the Chair. The Commission staff of 19 is made up of professional engineers, accountants, economists, and administrative staff. The Commission's offices are located in Vancouver at 900 Howe Street.

The Commission staff is made up of two main sections, the Information Services Group and the Regulatory Affairs and Planning Group. The Information Services Group handles complaints from ratepayers, provides research support, and compiles statistics and information to respond to inquiries from the public. The Regulatory Affairs and Planning Group comprises three units offering a range of functions: strategic services, rates and finance, and engineering and commodity markets.

Today's BCUC is much improved from the BCUC of the 1970's, 1980's and 1990's. It is smaller and more affordable, yet more efficient, effective and accountable. The Commission's future structure and functions will evolve quickly in 2003 as it begins to implement key policy actions from B.C.'s new energy policy, "Energy For Our Future, a Plan for BC" (referenced in this Annual Service Plan Report as the "Energy Policy" or the "Energy Plan"), and as a consequence of the Core Services Review. The BCUC's regulatory "tool kit" for implementing provincial policy includes oral and written public hearings, Alternative Dispute Resolution, incentive mechanisms, workshops and information publications.

The Vision

To be a leader in the regulation of energy providers within the mandate of the *Utilities Commission Act*, and to be respected for our independence, professionalism and competence.

The Mission

The Commission's mission is to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities it regulates and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital.

Our Values

The Commission is committed to realizing its vision and mission by:

- Applying regulatory principles, research and industry knowledge to resolve regulated utility issues and render decisions that are timely, fair, workable and respected.
- Writing high quality decisions, reports and publications.
- Communicating in an effective and timely manner with co-workers, utilities, ratepayers, government and the public.
- Promoting learning, innovation, creativity, and the achievement of personal and professional goals.
- Building a work environment that fosters teamwork, cooperation, and respect for the diversity, skills and experience of individuals.

Commission Services

In addition to its regulatory responsibilities, the Commission provides the following services and assistance:

- reviews ratepayers' complaints about the actions of utilities;
- provides copies of documentation prepared by the Commission (e.g., Brochures, Guidelines, Orders, Decisions, etc.) at no charge. These documents are also posted to the Commission's web site: *http://www.bcuc.com*;
- provides access to regulated utilities' Tariffs;
- provides access to information filed in public hearings; and
- responds to requests for general information regarding utilities.

Regulatory Functions and Responsibilities

The Commission meets regularly to review staff recommendations on utility applications, to authorize the issuance of Commission Orders or other directives considered necessary and in the public interest, to review complaints, and to conduct other necessary Commission business.

The regulatory tasks are carried out using an inter-disciplinary team approach. The team assigned to a task is normally composed of specialists from disciplines of engineering, accounting and economics and is advised, as appropriate, by legal counsel and specialist consultants retained by the Commission.

Over the last decade, the Commission has successfully reorganized, downsized and reduced its costs. Over the same period, the Commission has increased the effectiveness of its regulatory methods in an increasingly complex energy environment by streamlining its processes and adopting methods such as pre-hearing conferences, performance-based regulation and negotiated settlements.

Message from the Chair and Chief Executive Officer

I am pleased to report that the British Columbia Utilities Commission achieved the goals it set for itself for 2002/03 in its first Service Plan, dated January 30, 2002.

The BCUC's services are essential, affordable, and delivered effectively. The BCUC remains among the most efficient energy regulators in North America, operating at expenditure and staffing levels that are lower than comparable agencies. Indicators of Commission costs, activity levels and application cycle ("turnaround") times in 2002/03 compare favourably with past years and with other jurisdictions.

In November 2002, the Province released its new energy policy, "Energy for Our Future: A Plan for BC". The Energy Plan calls for a strengthened BCUC to fulfill its mandate of protecting the public interest by reviewing and approving energy rates, reliability standards and other conditions of service. The BCUC will be central to the successful implementation of many of the 26 Policy Actions that are set out in the Energy Plan.

Two core functions of the Commission are to set the revenue requirements for utilities, and then allocate these costs among customer classes through a rate design process. BC Gas' (now Terasen Gas) 2003 revenue requirements application was the subject of an oral public hearing in November 2002, while Pacific Northern Gas and Centra Gas' (now Terasen Gas Vancouver Island) revenue requirements applications were resolved by negotiated settlement processes. Settlement negotiations for Centra's rate design application were unsuccessful, so the Commission held an oral public hearing in February and March 2003. The Decision was issued on June 5, 2003.

2002/03 marked a transition year to conventional regulation for two utilities. BC Hydro's rate freeze expired on March 31, 2003. Activities unrelated to the freeze, often associated with new BC Hydro programs and projects, continued through the year. Centra's regulatory framework was established by Cabinet in its 1995 Direction to the Commission: starting in January 2003, Centra's rates are based on its costs, its competitive position, and the payback of pre-2003 revenue deficiencies.

The Commission also initiated workshops to educate stakeholders on emerging issues. These included sessions on the proposed Western Regional Transmission Organization ("RTO West") and sales by non-utility providers of natural gas to low-volume customers.

High and volatile natural gas commodity prices remain a concern for consumers' cost of living, businesses' operating costs, and gas utilities' sales volumes. The BCUC attempts to foster competition and choice by separating the natural monopoly (e.g., the pipe and the wires) from the activities amenable to market forces (e.g., the gas commodity and some customer services). For both gas and electricity, non-discriminatory access and pricing on transmission systems are necessary to facilitate competition.

For 2003/04 and beyond, the Province has given the BCUC new mandates associated with restructuring electricity, reviewing utility resource acquisition plans, and regulating the automobile insurance rates of the Insurance Corporation of B.C.

The BCUC strives to produce fair and timely decisions and findings, at a reasonable cost and in accordance with the principles of due process. The staff and Commissioners can be proud of their achievements in 2002/03, and I am confident that the Commission will continue to meet its goals in future.

Peter Ostergaard
Chair and Chief Executive Officer

The Year in Review

The most significant event in 2002/03 affecting the Commission's regulatory functions and responsibilities was the release by the Province of "Energy for Our Future: A Plan for B.C." in November. The Energy Plan has important implications for the Commission's regulation of both gas and electric utilities. Activities initiated by the Commission in 2002/03 resulting from the Energy Plan are described below, although most of the activities and impacts will occur in 2003/04.

Highlights in Operational and Financial Performance

Proceeding Days

The number of proceeding days fell in 2002/03 to a total of 30 (including hearings, dispute resolution, workshops, pre-hearing conferences, town hall meetings and meetings related to annual reviews of Performance Based Regulation agreements). There were 15 oral public hearing days in 2002/03, down from 23 in calendar 2001, which had been unusually high due to several non-recurring events. There were ten dispute resolution days in 2002/03 and three days dedicated to pre-hearing conferences and workshops.

The reduction in the total number of hearing days supports the Commission's view that the adoption of incentive regulation, negotiated settlements, and multi-year reviews will, in general, minimize the number of proceeding days.

As noted elsewhere, Commission costs in constant dollars decreased substantially from levels established in the early 1990's. Costs have remained roughly constant since 1998/99. Details and graphs are included in the section entitled *Performance Indicators* beginning on page 63.

Organizational Efficiency and Effectiveness

The staffing level at the Commission in 2002/03 stood at 19, as it has in the past four years. Staffing expenditure constituted approximately 64 percent of the Commission budget in 2002/03. The Commission has succeeded in maintaining or lowering its budget and core expenditures in real terms by moving away from the traditional cost-of-service approach to performance-based regulation, offering potentially lower regulatory costs. At the same time, interest-based negotiation often has proved more effective for settling differences among market participants. This results-based practice has allowed the BCUC to keep its costs reasonable in terms of the services to ratepayers and utilities.

Pursuant to Section 118 of the UCA, the BCUC has the authority to grant cost awards to intervenors in a proceeding before the Commission. The Commission has issued Participant Assistance Cost Award Guidelines to ensure that intervenors' submissions are useful, their efforts do not duplicate each other's, and costs claimed are reasonable. In 2002/03, the Commission issued five participant funding decisions totaling $110,385 in cost awards.

The costs of the Commission can be measured by cost per utility customer and cost per unit of energy sold. In fiscal 2002/03, the cost of regulation per customer is $0.91 (in $2002 dollars, down from $0.97 in 2001/02), primarily reflecting the lower number of hearing days. The cost of regulation per gigajoule ("GJ") of energy sold is 0.55 cents.[1] The total expenditure for fiscal 2002/03 was $2.45 million; the approved budget was $3.29 million. Expenditures decreased by approximately 5 percent over the previous year, largely due to the fewer number of hearing days.

Highlights in Natural Gas

British Columbia's natural gas market shares by utility suppliers are shown in Charts A and B.

Volatility continued in natural gas commodity markets, but costs moderated somewhat from past levels. In response to the volatile natural gas markets in 2001, the Commission established guidelines to mitigate the impacts on ratepayers. As part of its ongoing reviews of the commodity cost of natural gas, the Commission requires gas utilities to file Price Risk Management Plans. These plans outline the efforts of PNG, BC Gas and Centra Gas (the latter two companies now Terasen Gas and Terasen Gas Vancouver Island, respectively) to manage commodity price volatility through diversification of gas sources and pricing.

Utility Gas Cost Reconciliation Accounts are used to stabilize rates by crediting or debiting the variance in gas costs between those actually incurred and those forecast for the purpose of setting rates. The Commission requires utilities to file Quarterly Reports on Gas Supply Costs, which discuss the outlook for natural gas prices and the balance in the Gas Cost Reconciliation Accounts. Depending on the balance in the account, rate changes may be triggered when the ratio of gas cost recoveries to forecast gas purchase costs falls outside of a deadband of 95 and 105 percent.

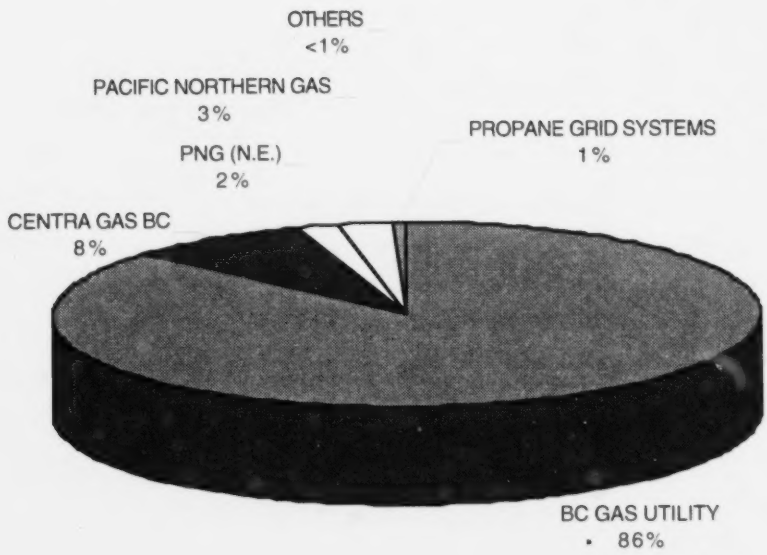
The moderation in the commodity cost of natural gas in late 2001 allowed the Commission to approve 5 to 8 percent rate decreases for BC Gas customers, and 11 to 15 percent decreases for PNG customers effective January 1, 2002. Although gas prices increased somewhat in the spring of 2002 due to colder weather and signs of economic strengthening in North America, a further rate decrease for PNG customers was ordered in March 2002 to reduce a credit balance in PNG's gas cost variance account. Rates for BC Gas and PNG customers remained unchanged for the remainder of the year. Rates for Centra Gas customers on Vancouver Island and the Sunshine Coast remained tied to prices of oil and electricity under a formula established in a 1995 Special Direction to the BCUC from the Province.

In late 2001 BC Gas applied for approval of a rate increase at the burnertip of about 2 percent effective January 1, 2002. These rates followed expiry of BC Gas' Performance Based Ratemaking Plan approved by the Commission in 1997 and extended through 2001. BC Gas subsequently withdrew its application due to a number of factors, and the Commission approved the withdrawal. BC Gas was directed to file a Revenue Requirements application for 2003. That application was filed in June 2002; the Commission held an oral public hearing into the application in November 2002, and issued its decision in February 2003. In a separate, written proceeding, the Commission approved the transfer of various customer care assets to BC Gas Inc. and then CustomerWorks, a limited partnership with Enbridge Inc.

[1] Total expenditure for 2002/03 of $2,445,000 ÷ calendar 2002 energy sales, as shown on pages 46 and 47, converted to GJ.

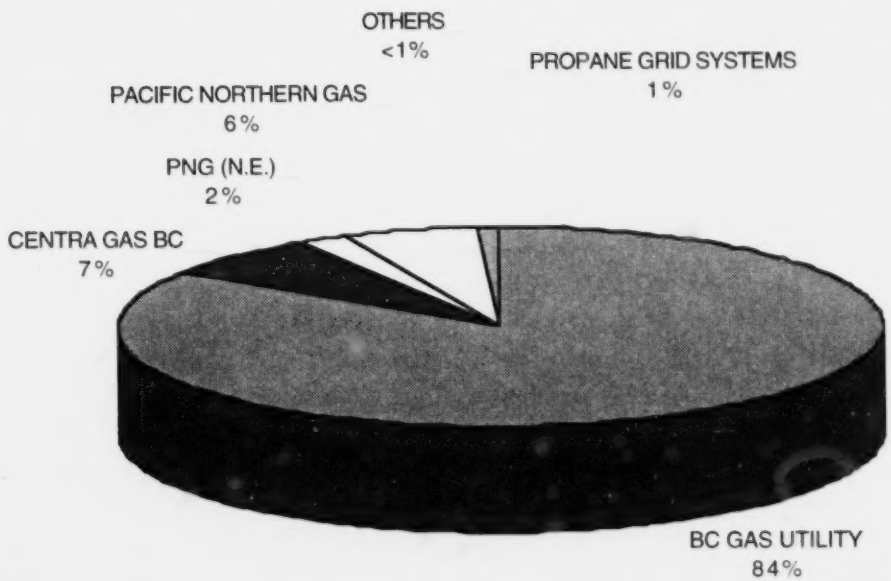
2002 DOMESTIC GAS SALES
Market Share by Number of Customers

Chart A



2002 DOMESTIC GAS SALES
Market Share by Revenue

Chart B



Following the release of the Province's Energy Plan, the Commission formally resumed work on unbundling gas service to extend the choice of gas commodity supplier to BC Gas' smaller volume customers. The Energy Plan signaled changes to the *Utilities Commission Act*, which would permit consumer protection measures under unbundling.

After an oral public hearing in Terrace and Vancouver, the Commission approved PNG's 2002 revenue requirements, including a load retention rate between PNG and Methanex Corporation. The 2003 rates were established through a negotiated settlement process. The Commission also approved revenue requirements for PNG (N.E.), which serves customers in Fort St. John, Dawson Creek and Tumbler Ridge, through a written hearing process in 2002 and 2003.

For most Centra Gas Vancouver Island and Sunshine Coast customer classes, the formula-based method for setting rates established by the 1995 Special Direction expired on December 31, 2002. In order to establish rates under more conventional revenue requirements and rate design methodologies, Centra filed a Revenue Requirements application, a Cost of Service Allocation ("COSA") study, and a Rate Design application during 2002. The Revenue Requirements application was resolved in December 2002 through a negotiated settlement process. A negotiated settlement could not be achieved for the COSA study/Rate Design application, and those were sent to an oral public hearing held in early 2003, with the Decision released in early June 2003.

Highlights in Electricity

British Columbia's electricity market shares by utility suppliers are shown in Charts C and D.

In June 2002 the Commission issued its Decision on the final routing of the UtiliCorp Networks Canada (British Columbia) Ltd. (now known as Aquila Networks Canada (British Columbia) Ltd. ["Aquila"]) 230 kV Kootenay System Development Project and the Brilliant Terminal Station Facilities Interconnection and Investment Agreement.

Under the terms of the 2000-2002 Settlement Agreement of the rates for Aquila's electric service, the Commission holds an Annual Review of the operation of the settlement and proposed rate adjustments. In November 2002, Aquila applied for a one-year extension of the existing Settlement Agreement, and in support of the application filed a preliminary 2003 Revenue Requirements Application. The Commission approved interim rates pending an Annual Review and Negotiated Settlement Process to determine final rates for 2003. The Commission also established a public workshop and written hearing process to review Aquila's December 2002 Application to construct a 500 kV substation to reinforce power supply to the South Okanagan. The Application was approved in April 2003.

The Commission established a written hearing process to review the 2002/03 Revenue Requirements for Princeton Light and Power Company, Limited ("PLP") and, after the written hearing, confirmed permanent rates for PLP.

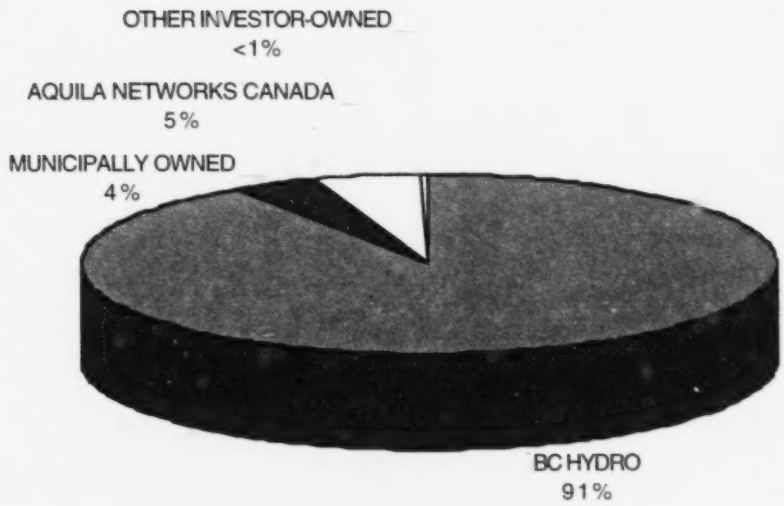
In December 2001, the Commission received a complaint from the Office and Professional Employees International Union ("OPEIU"). The complaint alleged that BC Hydro had violated, or was about to violate, Sections 52 and 53 of the Utilities Commission Act by seeking proposals for joint venture/partnership arrangements to provide services currently provided by BC Hydro, which would involve the disposition of part of its property. The Commission established a process for submissions from BC Hydro and the OPEIU and, following the submissions, denied the complaint in April 2002 by Order No. G-28-02. The OPEIU subsequently applied to the Commission to reconsider Order No. G-28-02. The Commission established a written submission process to determine whether the threshold for reconsideration had been met and, in July 2002, denied the Application. The OPEIU filed a similar complaint in December 2002.

The Commission approved for BC Hydro a new 230 kV underground transmission line from the Horne Payne substation in Burnaby to the Cathedral Square substation in downtown Vancouver. The new line is required to maintain electrical reliability to the downtown core. In March 2003, BC Hydro filed another Application for a Certificate of Public Convenience and Necessity to construct the Vancouver Island Generation Project at Duke Point. The oral public hearing of that application is underway.

In March 2003 the Province issued Order-in-Council 0253 along with Terms of Reference requesting the Commission to provide a report and recommendations relating to a Heritage Contract for BC Hydro's existing generation resources, and to stepped rates for industrial customers and transmission access. The Inquiry process leading to the Commission's report and recommendations is currently in progress.

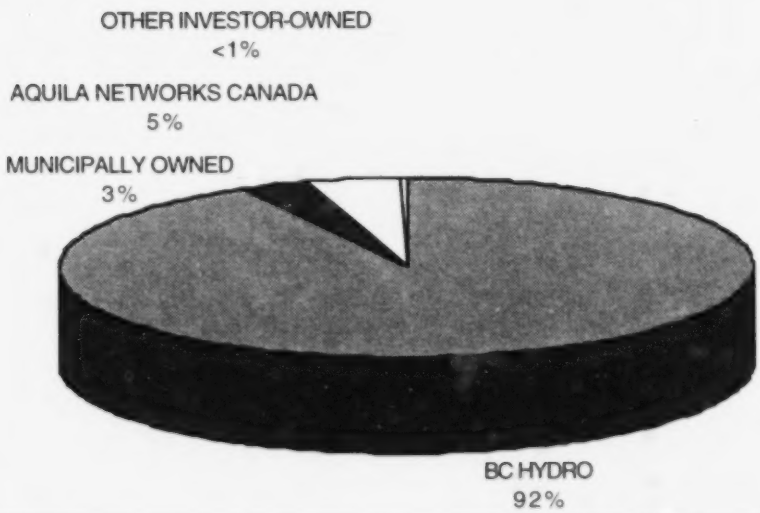
2002 DOMESTIC ELECTRICITY SALES
Market Share by Number of Customers

Chart C



2002 DOMESTIC ELECTRICITY SALES
Market Share by Revenue

Chart D



Report on Performance

The Commission has responsibility for setting rates and ensuring that consumers in British Columbia have access to reliable utility energy supplies at just and reasonable prices. The BCUC also has a mandate to deal with customer complaints of unfair treatment by utilities.

To effectively deliver its core business, the Commission has organized its regulatory functions by area of activity that are built on the knowledge of its inter-disciplinary teams. The primary areas of activities are:

(1) Revenue Requirements
(2) Rate Design
(3) Capital Projects Review
(4) Oversight of Energy Commodity Cost and Competitive Market Development
(5) Safety and Reliability
(6) Information Service and Complaints

It is the aim of the Commission to deliver the above core services in an efficient and effective manner without incurring unnecessary costs and burdensome regulatory requirements. The following tables present the goals, strategies and performance measures that have been established for each of the BCUC's core services and the actual 2002/03 fiscal year results of those intended goals and performances. The Strategies, Activities and Performance Measures and Targets are from the Commission's 2002/03 Service Plan that was tabled on January 31, 2002. The right-hand column summarizes what was actually achieved, and if applicable, how and why actual results varied from the intended results along with the current year's performance indicators.

GOAL 1: **Ensure that the regulated energy utilities are financially viable and capable of providing high quality service to customers.**

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
1. Return on Equity (ROE).	To allow utilities to incorporate results into their rates for the following year.	Calculation of the low-risk benchmark ROE at the end of each year.	Annual publication of ROE for low-risk benchmark utility by early December.	In November 2002, approved an ROE for a low-risk benchmark utility for 2003 of 9.42% to be used as the base for determining specific utility ROE's.	L-46-02	●
		Periodic review or public hearing to consider any necessary amendments to ROE adjustment mechanism.	Timely, clear and well-reasoned decision.	No review required in 2002 as written hearing was held in late 2001.	N/A	N/A
2. Review and Oversight of Utility Financing, Commodity Trading Hedging activities, and Gas Cost Variance Account Balances.	To ensure that the benefits to ratepayers are not outweighed by the risks involved.	Approval or feedback to the utility on its activities. Quarterly review of natural gas commodity costs.	Mark-to-market reports on hedging activities.	Ongoing.	Examples: G-19-02 L-13-02 L-14-02 G-38-02 L-22-02 L-24-02 L-37-02 L-40-02 L-41-02 L-50-02	●
			Comparison of utility commodity trading and financing activities to market conditions.	Ongoing.		◐
			Avoidance of disallowed expenditures and full recovery of all prudent commodity costs.	Ongoing. Example: Accepted recommendation that the current Gas Supply Charges and Gas Cost Variance Account riders for PNG-West, PNG(NE) and Granisle continue at their present levels effective October 1, 2002. The Commission recognized that PNG has no gas in storage for 2002/03, is limited in its hedging capability, and that current expectations indicate gas costs in the next 12 months are likely to be significantly higher than expected revenue. PNG was directed to monitor its forecast gas costs on an ongoing basis and to apply for changes to gas commodity rates prior to January 2003 if necessary.		●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 1: **Ensure that the regulated energy utilities are financially viable and capable of providing high quality service to customers.**

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
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		Periodic review or public hearing to consider any necessary amendments to ROE adjustment mechanism.	Timely, clear and well-reasoned decision.	No review required in 2002 as written hearing was held in late 2001.	N/A	N/A
2. Review and Oversight of Utility Financing, Commodity Trading Hedging activities, and Gas Cost Variance Account Balances.	To ensure that the benefits to ratepayers are not outweighed by the risks involved.	Approval or feedback to the utility on its activities. Quarterly review of natural gas commodity costs.	Mark-to-market reports on hedging activities.	Ongoing.	Examples: G-19-02 L-13-02 L-14-02 G-38-02 L-22-02 L-24-02 L-37-02 L-40-02 L-41-02 L-50-02	●
			Comparison of utility commodity trading and financing activities to market conditions.	Ongoing.		●
			Avoidance of disallowed expenditures and full recovery of all prudent commodity costs.	Ongoing. Example: Accepted recommendation that the current Gas Supply Charges and Gas Cost Variance Account riders for PNG-West, PNG(NE) and Granisle continue at their present levels effective October 1, 2002. The Commission recognized that PNG has no gas in storage for 2002/03, is limited in its hedging capability, and that current expectations indicate gas costs in the next 12 months are likely to be significantly higher than expected revenue. PNG was directed to monitor its forecast gas costs on an ongoing basis and to apply for changes to gas commodity rates prior to January 2003 if necessary.		●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 1 continued.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
3. Review of BC Hydro export trade activities.	To ensure that utility ratepayers are not put at risk by trading activities.	Requirement for quarterly reports on export trade.	Ongoing review.	The Commission reviews the reports as filed.	N/A	●
4. Approval of utilities' capital and operating expenditures.	To ensure that utilities are financially viable and capable of providing high quality service to customers.	Approval of capital and expense budgets to be recovered in utility rates.	Sufficient revenue to provide safe and reliable operations and to be financially viable.	The Commission continues to attain the target objectives and outcomes in this service activity. Example: (BC Gas) Approved Transmission Pipeline Integrity Plan Expenditures for 2001 and 2002, except for expenditures related to the Noons Creek to Eagle Mountain segment, for a total estimated cost of $7.469 million. BC Gas will address which project costs are capital expenditures, which should be expensed annually, and whether some costs should be deferred and amortized over an appropriate period in its next revenue requirements application. Example: (BC Gas) Approved the Armstrong Compressor Station project for a total estimated cost of $4.246 million, with a range of accuracy of plus or minus 10 percent. BC Gas is to advise the Commission of the date that the compressor becomes available for local manually-operated service, and file quarterly progress reports. A comprehensive final report is to be filed upon completion of the project.	Examples: C-03-02 C-06-02 *See also MSA-14*	●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 2: **Maintain and Improve Quality and Reliability of Utility Service**

Ensure that services are not disrupted and that quality of service remains high. This includes ensuring the security of energy supply, especially during peak use periods.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
5. Review of customer complaints, reliability and quality of service indicators, gas supply and power purchase plans, utility capital and operating plans, and capital project applications.	To ensure that necessary expenditures are made and activities are undertaken to provide high quality reliable service. To ensure that appropriate system upgrades are undertaken to accommodate system growth, to monitor and replace aging facilities and to incorporate improved technologies where appropriate.	Provisions in incentive settlement agreements to encourage utilities to provide high quality, reliable service based on agreed upon performance indicators. Review of utility capital plans and capital project applications.	Results monitored and compared to previous utility performance and industry standards. Adequate energy supply during peak periods. Timely, clear and well-reasoned decisions.	Ongoing. The Commission has continued to effectively manage and ensure the provision of adequate energy supply during peak periods. Example: (BC Gas) Established a Workshop and Pre-hearing Conference to review the 2003 Revenue Requirements and Multi-Year Performance-Based Ratemaking Application and to discuss procedural matters, including the desirability of a Negotiated Settlement Process for any or all components of the Application and the establishment of a multi-year performance-based regulatory mechanism. Example: (Centra Gas) Accepted for filing the December 12, 2001 Confirmation of Gas Sales Agreements with IGI Resources Inc. for the supply of 5,275 GJ/day of seasonal gas for the period December 13, 2001 to February 28, 2002. Example: (PNG-West) Accepted the October 24, 2002 Letter Agreement with Duke for the supply of firm Seasonal, Peaking and Super Peaking gas supplies for delivery to PNG at Station 2 from November 1, 2002 to March 31, 2003, pursuant to Section 71 of the Act and the Rules respecting Energy Supply Contracts. Example: (BC Gas) Approved the continuation of the Revelstoke supply of liquid propane from MP Energy and the continuation of a winter-fixed /summer-variable with price cap pricing structure that conformed to the strategy approved by Order No. E-8-01.	G-08-02 G-09-02 G-40-02 L-08-02 E-01-02 G-58-02 G80-02 G-89-02 L-29-02 E-08-02 *See also MSA-4, MSA-21*	●
						●
						●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 3: **Maintain and Improve Customer Satisfaction with Utility Service**

Customer Satisfaction with utility service is a composite of several factors, some of which are included under other goals.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
6. Operating Practice Review.	To encourage utilities to undertake "customer-friendly" operating practices. To direct utilities to address issues arising out of customer complaints. To provide customers with an opportunity to express their views on utility operations.	Incorporation of appropriate incentives in multi-year settlement agreements for utilities to improve service levels.	Improvement in service quality indicators over time for each utility.	The Commission tracks service quality indicators insofar as they are embedded components in utility PBRs. The Commission continues to direct utilities to address issues arising out of customer complaints. Example: (BC Hydro) Requested BC Hydro to review and provide the Commission with its comments regarding the complaint filed by the Office & Professional Employees' International Union, Local 378 regarding the proposed consolidation, amalgamation or merger of the utility. Example: (PNG, BC Gas and Centra Gas) Requested comments regarding the quarterly review process based on utility experience over 2001 and 2002 and the utility's assessment of the effectiveness of the quarterly reporting Guidelines. Example: (BC Gas) Approved the disposition of the BC Gas Program Mercury and other customer care related assets to BC Gas Inc., in accordance with the Asset Transfer Agreement. - Approved the two agreements with CustomerWorks, being a Client Services Agreement for the provision of customer care services, and a Shared Services Agreement for the provision of corporate support services. - BC Gas is to provide a Report and Recommendation to the Commission for review prior to the renewal of contracts with CustomerWorks in 2007, or before committing to another service provider.	L-01-02 L-05-02 G-29-02 G-73-02 L-40-02 L-41-02 *See also MSA-21*	●
		Ongoing feedback and communication between customers, the Commission and the utilities.	Customer satisfaction with management of their complaints (evaluated by periodic surveys of complainants).			●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 3 continued.

2002 Service Plan				2002 Service Plan Performance Report.		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
7. Development of New Services.	To respond to commodity competition and changing customer needs.	Approval of programs based on disclosure of economic information on program costs and consumer benefits. Published guidelines and other consultation documents. Firm commodity sales at market-based or annual fixed prices to industrial customers.	Programs provide benefits to customers and utilities at fair and non-discriminatory rates through fair, efficient processes. Acceptance of the program by the utility and customers or feedback leading to an improved program. Just and reasonable rates established through a timely and efficient hearing process. Competitive gas supply options provided for industrial customers without adverse cost impacts on other customers.	The Commission has continued to be successful at supporting the development of new services. Example: (BC Hydro) Requested a report on the General Service Time-of-Use Pilot Program and offered to work with the utility to develop a permanent program, which can overcome the initial shortcomings of the Pilot Program. Example: (Squamish Gas) Approved Squamish Gas' proposal that the competitive fuel rate setting mechanism continue beyond December 31, 2001 and that the stated discounts in Schedule A of the Squamish RSA are no longer applicable, effective January 1, 2003. Example: (Aquila) Approved amendments to the Electric Tariff Terms and Conditions allowing the customer the option to read the meter and supply the information for billing purposes. Example: (BC Gas) Approved Market-Based Commodity Rates for Rates Schedules 7, 10 and 14 and approved new Rate Schedule 14A for the 2002/03 gas contract year commencing November 1, 2002. Example: (BC Gas) Approved a further Amended and Restated Bypass Transportation Agreement for Dunkley Lumber Limited for a ten-year term, which replaced the current bypass Transportation Agreement filed as Rate Schedule 25, Tariff Supplement No. E-2. Example: (BC Hydro) Requested BC Hydro comment on the issues raised in an application for net metering for residential customers, pursuant to Energy Plan Policy Action No. 20.	G-32-02 G-54-02 G-66-02 G-98-02 G-95-02 L-02-02	●
						●
						●
						●

Satisfactory ●
Needs Improvement ◉
Unsatisfactory ○

GOAL 3 continued.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
B. Development of Options for Increased Choice of Commodity Supplier.	To implement more choice in natural gas supply at the small commercial and residential level. To provide customers with the option of buying gas from marketers, and allowing the marketers' gas supply charges to be included on utility bills.	BC Gas - Agency, Billing and Collection and Transportation Service Option (ABC-T). The program is to enable non-utility suppliers to offer various prices and term options for small customers who wish to buy gas from brokers and marketers. The Commission assesses the cost of this unbundling program and the benefits of choice to potential customers.	Establishment of a workable ABC-T program by November 2003, if sufficient interest and authority for appropriate consumer protection (licensing of marketers).	Legislative amendments to the UCA, supporting consumer protection aspects of ABC-T, passed in May 2003. Pursuant to Policy Action No. 19, the Commission requested BC Gas to develop a detailed report relating to unbundling residential and commercial gas sales, Agency, Billing and Collection for Transportation Service. - A schedule and cost estimate to achieve an implementation date of November 2004 for ABC-T service. - A consultative process for addressing marketers' concerns (such as supply balancing requirement and the proposed one year contract with consumers). - Review of Alternative rate offerings that BC Gas proposes to provide in conjunction with ABC-T service. Approved the recovery of $106,328 of actual deferral account costs incurred for the ABC-T project.	L-49-02 G-27-02	●
			Resolution of franchise fee issues with utilities and local governments prior to establishment of ABC-T Service.	Ongoing. Franchise fee revenue implications to municipalities of non-utility gas supplies to core market customers remains uncertain. Example: Approved a 1-year extension of the Operating Agreement with the District of 100 Mile House and continuation of the payment of franchise fees.	C-01-02 C-02-02 C-08-02 C-12-02 C-13-02	◐

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 4: **Enhance Provincial Competitiveness Through Non-Discriminatory Services**

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
9. Rate Design Reviews.	To apportion the revenue requirement fairly to different classes of customer, while ensuring there is no undue discrimination in the rate structures of the utilities.	Centra Gas – Review of 2002 Rate Design Application.	Fair, just and reasonable rates.	Following an unsuccessful negotiated settlement process, an oral public hearing process was established to determine rate class segments and permanent rates.	G-71-02 G-76-02 G-86-02 G-96-02 G-97-02 L-19-02 L-24-02 L-35-02	●
			Timely, clear and well-reasoned decision.	Decision on permanent rates issued on June 5, 2003, less than two months after receipt of final arguments.		●
		BC Hydro – Application expected in late 2003 or 2004 including review of rates.	Fair, just and reasonable rates.	BC Hydro rate application deferred until early 2004. Approved amendments to Rate Schedules 1852 and 1880. Proposal regarding Heritage Contract, Stepped Rates and Access Principles filed in 2003. Inquiry established pursuant to Order-in-Council 0253, with report to be filed by October 17, 2003.	G-99-02 G-23-03	●
			Timely, clear and well-reasoned decision.			N/A
		PNG – a fully allocated cost of service (FACOS) study to be done in conjunction with its 2003 revenue requirements application.	Fair, just and reasonable rates.	Commission approved a Negotiated Settlement Agreement in which parties agreed to review the results of the FACOS study in a future proceeding. PNG was directed to monitor its forecast gas costs on an ongoing basis and to apply for changes to gas commodity rates prior to January 2003 if necessary.	G-56-02 G-84-02 G-91-02 G-92-02 L-40-02 G-14-03	●
			Timely, clear and well-reasoned decision.			●

Satisfactory ●
Needs Improvement ◉
Unsatisfactory ○

Goal 4 continued.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
10. Review of Utility Tariffs.	To ensure that tariffs apply equally to all customers in similar circumstances.	Tariffs for approved utility programs and services that respond in a fair and non-discriminatory manner to requests for the service to be provided under the tariff.	Tariffs that provide the same service to customers at a cost that is fair and non-discriminatory.	Consistent with its mandate, the Commission continues to ensure the provision of non-discriminatory service at fair rates. Example: (Centra Gas) Approved interim rate class segments for Centra under its 2002 COSA Study. Decision on permanent rate class segments is a component of the June 5, 2003 Decision on the 2002 Centra Rate Design Application. Example: (BC Gas) Approved Rate Schedule 22B - Large Industrial Rate Tariff Supplements No. G-14 and G-15 with Fording for its coal mine site operations at Fording River and Greenhills, effective August 1, 2002.	G-70-02 G-97-02	●
11. Resolution of Tariff Complaints.	To monitor and respond to customer complaints that tariffs are not fair or that utilities are not following their tariffs.	A resolution to the complaint based on the particular circumstances.	A response from the Commission to the utility and the complainant that provides a well articulated and well reasoned resolution to the complaint.	The Commission handled 390 complaints about utility rates, bill estimates, disconnections, and other tariff issues in 2002/03. It intends to lessen its reliance on utilities in the investigation of some complaints, and reduce the time taken to rule on them.	P-02-02 P-03-02 *See also MSA 22*	◐
12. Regional Electricity Transmission.	To implement and manage changes in the electricity industry consistent with provincial electricity policies, regulation of transmission operators and their participation in a larger Regional Transmission Organization (RTO West) for western Canada and the United States.	Transmission rates may have to be unbundled from the current integrated rates.	Review and monitoring of transmission entities and RTO regarding performance, reliability, efficiency and, where applicable, profitability. An efficient transmission system in British Columbia with non- discriminatory rates.	The Commission continues to play an important role in managing regional transmission issues. It sponsored a Workshop in December of 2002, attended by about 100 stakeholders, on proposals for RTO West and implications for BC. Example: (BC Hydro) Approved amendments to Rate Schedule 1852: Transmission Service - Modified Demand and Rate Schedule 1880. Example: (Aquila) Approved the final routing for the Kootenay 230 kV Project and the Brilliant Terminal Station Facilities Interconnection and Investment Agreement with Columbia Power Corporation and Columbia Basin Trust.	G-45-02 G-46-02 G-99-02 C-05-02 C-10-02 L-03-02	● ●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 5: Enhance Provincial Competitiveness Through the Containment of Cost of Service Increases

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
13. Revenue Requirements Reviews.	To ensure that expenditures are required and reasonable for the activity. To approve a settlement agreement, or a Commission Decision establishing a certain level of costs to be included in the utilities' rates.	Pacific Northern Gas 2002 Revenue Requirements Review.	Safe, reliable, reasonably priced services. Opportunity for utilities to earn fair return on investment.	Commission Decision on the 2002 Revenue Requirements Application and the Methanex Application for a Load Retention Rate. Decision relating to the 2002 Revenue Requirements Application approving a reduction in the revenue deficiencies for the Fort St. John/Dawson Creek Division and Tumbler Ridge Division. PNG(N.E.) was directed to refund excess payments with interest back to customers. Scheduled a Negotiated Settlement Process commencing February 10, 2003, to examine the 2003 Revenue Requirement Application. Approved interim rate increases until the process to determine permanent rates was complete.	F-03-02 F-04-02 G-03-02 G-04-02 G-20-02 G-31-02 G-56-02 G-57-02 G-67-02 G-72-02 G-77-02 G-91-02 G-92-02 L-06-02 L-15-02 L-16-02 L-31-02 L-32-02	●
			Timely, clear and well-reasoned decisions.			●
		BC Gas 2003 Revenue Requirements.	Safe, reliable, reasonably priced services. Opportunity for utilities to earn fair return on investment.	The Commission established a hearing held in November 2002, and established interim rates until its Decision was complete.	C-03-02 G-07-03 G-37-02 G-40-02 G-52-02 G-63-02 G-90-02 L-42-02	●
			Timely, clear and well-reasoned decision.	The Commission issued its Decision in February 2003 establishing the utility's 2003 Revenue Requirement.		●

Satisfactory ●
Needs improvement ◐
Unsatisfactory ○

GOAL 5 continued.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
		Revenue Requirements for Smaller Utilities such as Aquila, Centra Gas, PLP.	Safe, reliable, reasonably priced services. Opportunity for utilities to earn fair return on investment.	Example: (Centra Whistler Negotiated Settlement) Approved the 2002/03 Revenue Requirements Settlement Agreement, which confirms the interim energy charge for all customers of $11.613/GJ, and a Gas Cost Deferral Account Rider of $0.987/GJ, effective January 1, 2002.	G-16-02 G-35-02 G-36-02 G-43-02 G-44-02	●
			Timely, clear and well-reasoned decisions.	Example: PLP written hearing and Holding Account application. PLP is to provide comparative financial schedules as prescribed by the Commission, whenever it applies for a change in rates, accounting treatment, or when submitting its Annual Report. Those schedules must set out the cost components of the various rate categories, such as access, service, energy, as well as the contracting activities. In future Applications, PLP must provide a detailed reconciliation of its revenue deficiency showing specific changes in its costs and gross margin.		●
14. Review of utility major capital projects through applications for Certificates of Public Convenience and Necessity.	To ensure that major capital projects are necessary, least-cost and the best alternative. To provide for an appropriate level of public input or a combination of hearings and settlement processes.	BC Gas – Approval of Transmission Pipeline Integrity Plan.	BC Gas is directed to file an annual report on the expenditures and results of the multi-year plan.	The Commission approved Transmission Pipeline Integrity Plan Expenditures for 2001 and 2002, except for expenditures related to the Noons Creek to Eagle Mountain segment, for a total estimated cost of $7.469 million. An accounting treatment of project costs will be reviewed in BC Gas' next Revenue Requirements application. BC Gas will file an annual report on TPIP activities during the year.	C-03-02	●
		BC Gas – possible application to construct Inland Pacific pipeline.	Process established to review the application.	BC Gas has not yet filed an application.	N/A	N/A

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 5 continued.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
		Centra Whistler – anticipated application to construct a natural gas pipeline.	Process established to review the application.	Centra Whistler filed a "Long Term System Development: Review of Alternatives" report that concluded a pipeline is not the preferred resource option at this time. The Commission is monitoring Centra Whistler's assessment of options for long term capacity.	N/A	●
		System Reinforcement Applications.	Process established to review the application.	Example: Established a written public hearing for the review of the Aquila CPCN application for the South Okanagan Supply Reinforcement Project and BC Hydro's application to amend the General Wheeling Agreement and Power Purchase Agreement with Aquila. Example: Established a written public hearing to review the CPCN Application for the Installation of New Circuit 2L33 from Horne Payne Substation (Burnaby) to Cathedral Square Substation (Vancouver).	G-75-02 G-100-02	●
			Timely, clear and well-reasoned decisions following a review.	Examples: Armstrong Compressor Station Project (BC Gas) Routing of 230 kV Kootenay System Development Project (Utilicorp Networks Canada) Installation of new 230 kV Circuit 2L33 (BC Hydro) Dam Rehabilitation for Upper Bonnington Unit 5 (Aquila)	C-06-02 C-14-02 G-46-02 L-43-02	●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 5 continued.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
15. Utility Gas and Electricity Procurement Oversight	To ensure that utilities purchase reliable supply of natural gas and electricity at the lowest overall cost.	Under the Act, utilities must file energy supply contracts with the Commission, which is to determine if the contract is in the public interest. Many utilities also file price risk management plans or electricity purchase plans, and file quarterly reports on the results of hedging activities and gas cost variance account balances.	Natural gas and electricity at the lowest possible long-term cost consistent with reliable supply and limited exposure to price volatility.	Example: (BC Gas) Accepted for filing the new gas supply contracts and gas supply contract amendments entered into by BC Gas with numerous gas suppliers. Example: (PNG) Accepted revisions to the 2002/03 Gas Supply Price Management Plan effective for the gas contract year commencing November 1, 2002. The revisions provide PNG with discretion regarding the timing and type of risk management actions. PNG is required to inform the Commission of its actions on an ongoing basis. Example: (BC Gas) Accepted for filing draft Letter Agreement dated March 15, 2002 with Puget Sound Energy Inc. for natural gas storage, subject to timely filing of the fully executed agreement. Example: (Centra Gas) Accepted for filing a Gas EDI Base Contract for Short-Term Sale and Purchase of Natural Gas for up to 5,273 GJ/day for the period of December 1, 2002 to March 1, 2003 at the Huntingdon, B.C. delivery point.	E-03-02 E-04-02 E-05-02 E-06-02 E-12-02 L-45-02	●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 6: **To Provide Standards to Maintain and Improve Public and Worker Safety**

Utility equipment should be designed, operated, and maintained to provide safe and reliable service to customers. Some of the natural gas and electricity plant is aging to the point where increased inspections, maintenance, and renewal plans are required.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
16. Western Electricity Coordinating Council (WECC) related activities.	To approve the Reliability Management System Agreement and the Reliability Criteria Agreement, and any changes to them, as they apply to BC's electricity utilities.	Secure and reliable operations resulting from the standards and criteria set out in the Agreements.	British Columbia electricity utilities meet or exceed the applicable safety and reliability standards.	The Commission monitors/investigates WECC Reports with regard to BC Hydro's and Aquila's compliance with the WECC RMS agreement. The Commission also monitors/investigates the reliability performance of these utilities. Several outage reports were reviewed.	N/A	●
17. Other Activities.	To Provide Standards to Maintain and Improve Public and Worker Safety.	Measurements against the safety and reliability targets. New safety and reliability measures when new issues are identified.	Improvements in safety and reliability indicators.	The Commission is cognizant of safety and reliability indicators and seeks to monitor and incorporate applicable standards into determinations as appropriate. Example: Utilicorp Networks Canada and BC Gas have multi-year settlements of revenue requirements that include financial incentives, which can only be earned if safety and reliability targets are met.	N/A	●
	To monitor and follow-up safety-related incidents within the Commission's jurisdiction.	Reports from the utilities on the causes of the incidents and any steps or improvements that can be taken to prevent further incidents.	Reductions in the numbers and severity of safety related incidents.	The Commission receives reports and updates on safety related incidents. Example: (BC Gas) The Commission received a report on and actively monitors issues of soil stability affecting the natural gas distribution system in the West Quesnel area. Example: (BC Gas) The Commission requested and received a Continuous Improvement Update as part of its monitoring of the Distribution line break in Chetwynd in September 2001.	N/A	●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 7: **To Control and Reduce the Cost of Regulation**

The Commission uses two key strategies to further this goal.

1. Continuing its Efforts to Streamline the Regulatory Processes
2. Ongoing Review of the Commission's Work Processes

These are highlighted further in tables that follow.

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
18. Ongoing review of all Commission activities.	To determine if Commission activities are necessary and, if so, if they are the most efficient and cost-effective method for achieving the desired outcome. To maintain Commission budgets and core expenditures at or below current levels, adjusted for inflation.	Annual Performance Indicators on staff levels, decisions issued, hearing days, Alternative Dispute Resolution days, Commission expenditures, Commission costs per customer, and Commission costs per gigajoule of energy sold.	Publish performance indicators in Annual Reports and Annual Service Plans.	Ongoing. Please see the relevant sections of this 2003 Annual Report and the 2003/04 Service Plan for a detailed summary.	2003 Annual Report 2003/04 Service Plan	●
			Maintain or improve performance as measured by indicators.	Ongoing. The Commission continues to update and improve its reporting framework for monitoring and improving performance in all Commission activities. Example: Starting in 2003, the Commission is tracking turnaround ("cycle") times for four categories of Applications and is comparing them with other tribunals where valid.		●
			Maintain favourable benchmarking of BCUC staffing and budget statistics against those of comparable tribunals.	The Commission performs well in benchmarking statistics compared to other tribunals (see reference above).		●
19. Review of the Utilities Commission Act and Regulations.	To reduce the regulatory burden where prudent or recommended.	Outdated regulations have been recommended to be rescinded or cancelled.	Reduce number of regulations or regulatory requirements by up to one-third by 2004/05.	221 regulatory requirements have been terminated. About 100 more requirements are expected to be terminated in 2003/04 in order to achieve the target reduction (given total requirements initially numbering 1,096).		●
20. Consultancy to other jurisdictions.	To provide revenue and enhance reputation and knowledge of the Commission and staff.	Staff regularly provide assistance to Yukon Utilities Board and Saskatchewan Rate Review Panel.	Revenue from services offsets BCUC costs and enhances reputation and knowledge of the Commission and staff.	Staff continue to provide expert review and support to these two jurisdictions on a cost recovery basis when workloads permit.		●

Satisfactory ●
Needs Improvement ◐
Unsatisfactory ○

GOAL 8: To Improve Communications About, and Ratepayers' Satisfaction with, BCUC Regulatory Matters

2002 Service Plan				2002 Service Plan Performance Report		
Major Service Activity (MSA)	**Objective**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
21. Issuing clearly written decisions and judgements.	To enable non-specialists and specialists to understand the Commission's reasoning in resolving detailed and complex issues.	Clear, readable and plainly written decisions and orders.	Favourable feedback from utility personnel and customers.	Ongoing.	N/A	●
22. Responding to Complaints.	To respond appropriately to customer complaints in a timely fashion. To rule on complaints fairly and efficiently, while balancing the needs of the complainant, other customers, and the utility.	Current procedures are articulated in the Commission's "Complaint Handling" pamphlet.	Improved satisfaction levels by complainants with the clarity of the Commission's explanations (from Stakeholder Assessment Reports).	Updated pamphlets that advise the public of the services that the BCUC provides.	N/A	◉
		Review of complaint management process, including allocated resources and the means of communicating decisions.	Complaints Management Review Report by mid-2002.	Complaints Management Review Report completed in 2002. Complaints tracking system implemented in 2002.	N/A	●
23. Periodic assessment of public confidence in regulatory process.	To maintain and improve satisfaction ratings with the BCUC by utilities, intervenors and complainants.	Periodic Stakeholder Assessment Reports, including stakeholder satisfaction ratings for comparison with baseline ratings.	Maintained or improved satisfaction ratings with the BCUC by utilities, intervenors and complainants.	Stakeholder Assessments completed in late 2000 and early 2002.	N/A	N/A

Satisfactory ●
Needs Improvement ◉
Unsatisfactory ○

Two Key Strategies to Control and Reduce the Cost of Regulation

2002 Service Plan				2002 Service Plan Performance Report		
Strategy	**Major Service Activity**	**Output, Outcome**	**Target or Quality Indicator**	**Results, Implications, Comments**	**Order, Letter or Other Reference**	**Overall Rating**
1. Continue to streamline the Regulatory Process.	Regulatory convergence and cooperation.	Participate in provincial, national, and North American initiatives that promote information sharing, joint processes, reduced duplication, best practices, and common regulatory principles.	Organize and host the annual educational conference for Canadian regulators ("CAMPUT"), utilities and other interested parties in May 2002.	Informative and productive conference successfully organized.	N/A	●
			Continue to participate in inter-jurisdictional forums to exchange views and develop harmonized practices where appropriate.	Staff and commissioner participation and speaking agreements in 2002/03 at CAMPUT, International Association of Energy Economists, BC Hydro, and other conferences.	N/A	●
	Periodic review of Commission policies, procedures, programs, processes, and generic decisions.	Publication of Commission Decisions or Guidelines on generic issues such as the multi-year ROE adjustment formula or the Commission's Guidelines on Participant Funding or Utility System Extension Tests.	Ongoing.	Ongoing.	N/A	●
2. Review and improve the Commission's work process.	Document Logging and Tracking.	Computer-based logging, tracking and assignment system implemented since November 2001. Assess internal processes and develop information on efficiency of internal document processing.	Improved information on and reduced response times for routine applications, queries and complaints.	Ongoing. Please refer to MSA-18.	MSA-18	●
	Review of Job Descriptions and Compensation Levels.	Accurate and up-to-date job descriptions and defined compensation ranges, consistent with the Province's forthcoming new compensation mandate.	Spring 2002 review.	With the assistance of a consultant, a review of all job descriptions, a new performance management system, and a new compensation framework for staff began in the summer of 2002, received approval of the Public Sector Employers Council in the spring of 2003,and was implemented effective March 30, 2003.	N/A	●

Satisfactory ●
Needs Improvement ◉
Unsatisfactory ○

Financial Report

Commission Recovery and Expenditure Summary

Authority for Cost Recovery

Beginning in 1988, the Commission was authorized to recover its costs from regulated utilities and pipeline companies by fixing levies according to Section 125 of the *Utilities Commission Act* and parameters set out in the Levy Regulation (BC Reg. 283/88). The Commission recovers most of its costs from a "per gigajoule" levy assessed on each utility, based on the amount of energy it sold in the previous calendar year. The Commission also bills utilities for its hearing costs that are attributed directly to those utilities. Direct recoveries have varied significantly from year to year, depending on the number and duration of regulatory hearings and inquiries. Minor revenues are also collected from intraprovincial petroleum pipeline companies and from other utility regulatory agencies that contract with the Commission for advice and assistance.

Levy 2002/03

The Commission is often able to underspend its annual budget due to the successes it has experienced in streamlining its proceedings and encouraging multi-year performance-based ratemaking through cost-effective negotiated settlements. The fixed and recurring costs of the Commission are approximately $2.5 million, with added costs resulting from increased hearing loads. Additional hearing days may occur due to referrals of issues by the government (e.g., Heritage Contract Review in 2003/04) or unusually complex regulatory issues requiring hearings (e.g., WKP's proposed sale of hydroelectric assets). Although the direct costs of hearings are typically recovered from applicants, the out-of-pocket costs for legal services, court reporting and consultants also show in the Commission's expenditures.

The Commission's fiscal year runs from April 1 to March 31. The voted expenditure for the 2002/03 fiscal year was $3,294,000. Of this, $86,000 was forecasted to be recovered directly from utilities for Commission expenditures attributable to their public hearings and other proceedings under the Act. This left a net annual budget of $3,208,000 to be recovered from the levy, as identified in the formula below.

$$\frac{\text{Total Budgeted Expenditures } \textbf{minus} \text{ estimated Direct Recoveries (\$)}}{\text{Total Utility Energy Volumes sold in previous calendar year (GJ)}} = \frac{\$3,208,000}{414,820,300\ \text{GJ}} = \$0.00773347/\text{GJ}$$

The Commission's costs were therefore expected to be recovered from a levy of $0.00773347/GJ for the fiscal year beginning April 1, 2002, payable by utilities in four quarterly installments. The levy for the last quarter of fiscal year 2001/02 (i.e., January 1 through March 31, 2002) was $0.00671079/GJ.

Levy Billing Adjustments

Lower than forecasted Commission expenditures in the 2001/02 fiscal year resulted in a year-end credit from 2001/02 levy payments received of $714,758. This amount was credited to the utilities in their first quarter billing for

2002/03. The second, third and fourth quarter billings were at the full levy rate of $0.00773347/GJ. An actual end of fiscal year 2002/03 surplus of $922,509 will be credited to utilities in the first and second quarter levy calculations in 2003/04.

2002/03 Revenues and Expenses

Levy billed and Recoveries received in 2002/03	$2,652,952	
Add: Deferred Revenue from 2001/02 Levy	714,758	
Total Recoveries (see below)		**$3,367,710**
Less: Expenditures (see below)		2,445,201
Revenue deferred to 2003/04		**$ 922,509**

The levy amounts recovered from utilities and other revenue sources for the 2002/03 fiscal year are as follows:

Commission Revenues Recovered Through the Levy (Order No. G-33-02)	**Amounts Recovered 2002/03 Fiscal Year (Actual)**
Aquila Networks Canada (British Columbia) Ltd. (formerly UtiliCorp Networks Canada (British Columbia) Ltd.)	$ 40,834
British Columbia Hydro and Power Authority	1,005,695
Central Heat Distribution Limited	7,330
Corporation of the City of Nelson	1,124
Hemlock Valley Electrical Services Limited	21
Pacific Northern Gas Ltd.	161,245
Pacific Northern Gas (N.E.) Ltd.	
- Dawson Creek and Fort St. John	25,503
- Tumbler Ridge	4,482
Port Alice Gas Inc.	108
Princeton Light and Power Company, Limited	1,302
Silversmith Power & Light Corporation	2
Stargas Utilities Ltd.	209
Sun Peaks Utilities Co., Ltd.	289
Terasen Gas Inc. (fomerly BC Gas Utility Ltd.)	
- Lower Mainland Division	704,919
- Inland Division	324,330
- Columbia Division	44,413
- Fort Nelson Division	5,288
Terasen Gas (Vancouver Island) Inc. (formerly Centra Gas British Columbia Inc.)	162,920
Terasen Gas (Squamish) Inc. (formerly Squamish Gas Co. Ltd.)	1,979
Terasen Gas (Whistler) Inc. (formerly Centra Gas Whistler Inc.)	4,127
Terasen Multi-Utility Services Inc. (formerly Sun Rivers Services Corp.)	23
The Yukon Electrical Company Limited	16
	2,496,159

Recoveries from Intra-Provincial Oil Pipeline and Other Companies

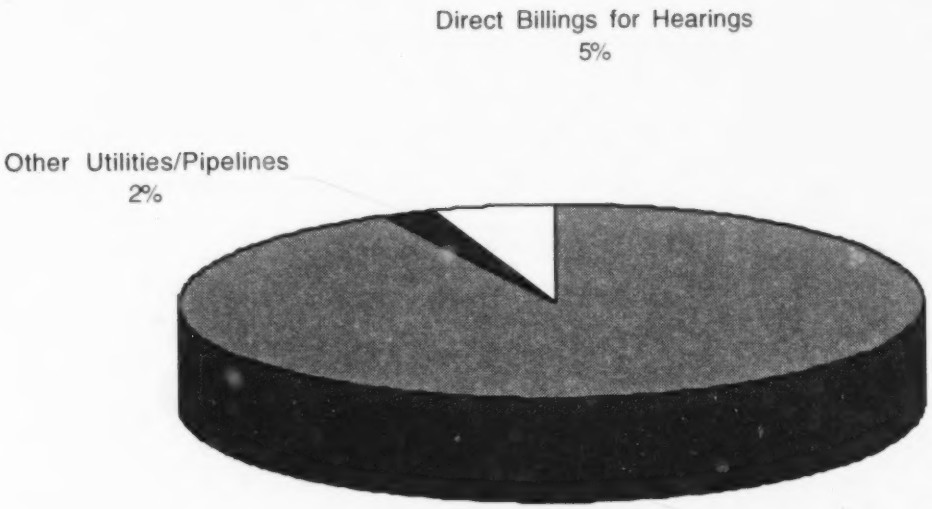
Duke Energy Field Services Canada Ltd.	1,000
Coastal Canada Field Services	1,000
EnerMark Inc. (formerly Newcal Energy Inc.)	1,000
JJH Equipment Trust	1,000
Plateau Pipe Line Ltd.	4,000
Williams Energy Canada Ltd.	1,000
Terasen Pipelines (Jet Fuel) Inc. (formerly Trans Mountain Enterprises of British Columbia Limited)	1,000
Westcoast Gas Services Inc.	1,000

Miscellaneous Revenues

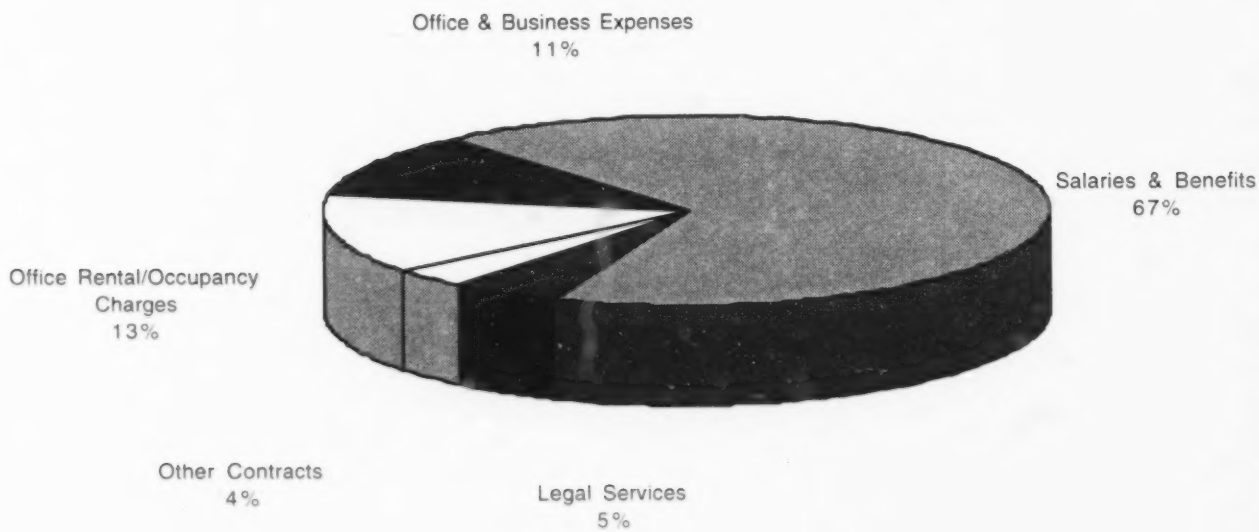
Commission Contracts with:	
- Yukon Utilities Board	4,266
Recovery of Proceeding Costs from Utilities	140,564
Recovery of Room Rental and Photocopying Costs	963
Deferred Revenue from 2001/02 (credited to utilities' first quarter billing in 2002/03)	714,758
TOTAL REVENUES	**$3,367,710**

Commission Expenditures per Expense Category	**Amounts Spent 2002/03 Fiscal Year (Actual)**
Commission and Staff Salaries and Benefits	$1,582,078
Commissioner Fees and Expenses	89,535
Travel	54,671
Professional Services	197,303
Information Systems	58,577
Office and Business Expenses	91,198
Advertising and Publications	23,182
Amortization	40,348
Leasehold and Occupancy Charges	315,168
Other Expenses (net)	(6,859)
TOTAL EXPENDITURES	**$2,445,201**

REVENUES



EXPENDITURES



Corporate Governance

The *Utilities Commission Act* provides for a Chair, one or more Deputy Chairs, up to seven Commissioners [including the Chair and Deputy Chair(s)], and temporary Commissioners. As of March 31, 2003, there are four temporary Commissioners, one full-time Commissioner and the Chair.

Following are brief biographies for Commissioners and temporary Commissioners serving in the 2002/03 fiscal year:

Peter Ostergaard, Chair

Queen's University, 1973 [B.A. (Honours) Geography and Economics]; University of British Columbia, 1976 (M.A.); Member, Canadian Institute of Planners; 1990-96 Assistant Deputy Minister, Energy Resources Division, Ministry of Energy, Mines and Petroleum Resources; 1996-97 Assistant Deputy Minister, Energy and Minerals Division, Ministry of Employment and Investment; January, 1998 appointed Chair and Chief Executive Officer.

Robert H. Hobbs, Commissioner

Brandon University, 1979 (Mathematics); University of Manitoba, 1982 (LL.B); University of Western Ontario, 1987 (M.B.A.); 1989-2001 Aquila Networks Canada (British Columbia) Ltd., last position held Vice President, Regulatory and Legislative Services; Member of the Law Society of British Columbia (inactive); appointed full-time Commissioner March, 2003.

Kenneth L. Hall, Temporary Commissioner

University of Saskatchewan (B.E.), Professional Engineer, Trans Mountain Pipe Line Company (30 years) retired 1983 as President, C.E.O. and Chairman of the Board; Honorary Life Member Canadian Petroleum Association; appointed December, 1989.

Paul G. Bradley, Temporary Commissioner

Cornell University, 1956 (B. Chemical Engineering); Massachusetts Institute of Technology, 1966 (Ph.D. Economics); Postdoctoral Fellow, Sloan School of Management, MIT (1969-70); Visiting Scholar, Centre for Energy Policy Research, MIT (1978-79); Director, Mineral Revenues Inquiry, State of Western Australia (1984-86); Resident Consultant, Dept. of Energy, Mines & Resources, Ottawa (1987), Professor Emeritus, University of British Columbia (1965-96); appointed September, 1992.

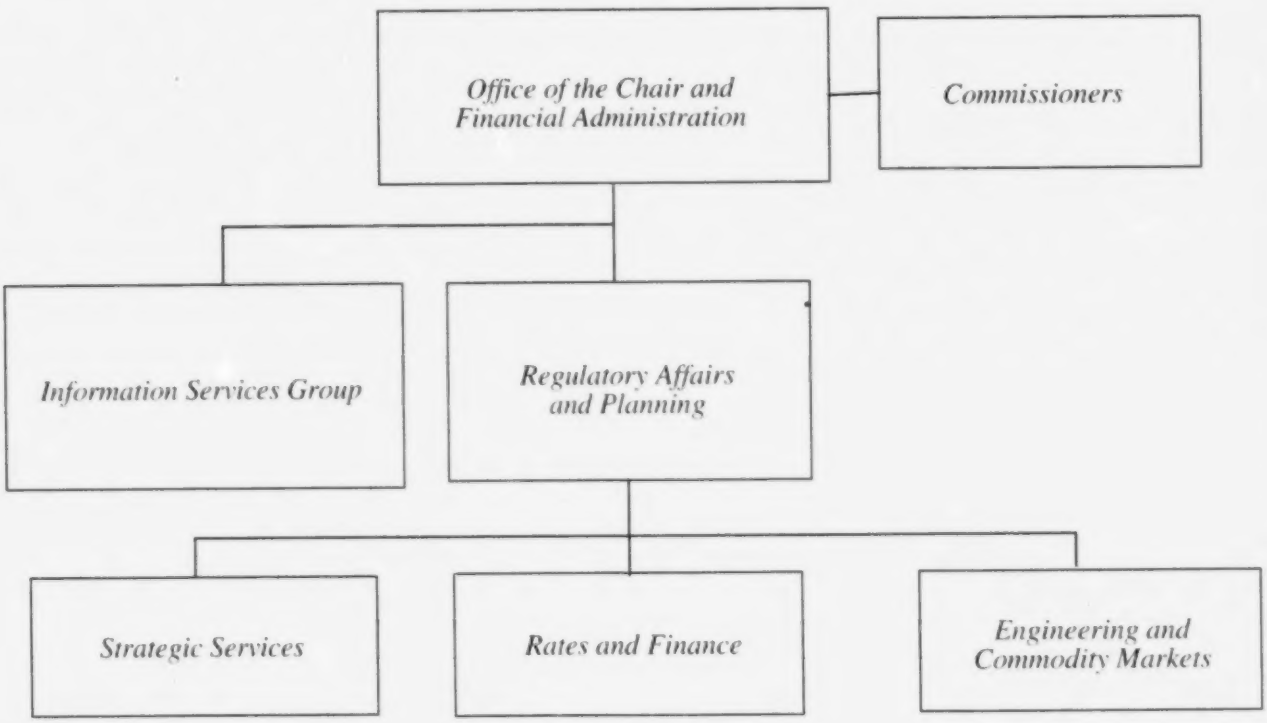
Nadine F. Nicholls, Temporary Commissioner

University of British Columbia, 1976 (B.Sc. Mathematics); University of British Columbia, 1982 (M.Sc.); rates economist, British Columbia Hydro and Power Authority (1980-83); electricity utilities advisor, Government of the Northwest Territories (1990-92); energy policy consultant in the Northwest Territories (1993-98); appointed March, 2000.

Richard (Kim) R. Deane, Temporary Commissioner

University of British Columbia (B.A. Sc. Electrical Engineering), Professional Engineer, Distribution Engineer, Wellington, New Zealand (1965), mine design and construction with M.A. Thomas & Associates (1966-68) and Placer Development (1968-72), Manager, Transmission and Distribution, West Kootenay Power Ltd. (1976-81) and Manager, Energy and Services, Cominco Trail (1982-2000); appointed March, 2001.

The organization chart below shows the reporting structure within the Commission.



The Commission has one subcommittee to manage human resources, performance management, and compensation issues. Members are Peter Ostergaard, Robert Hobbs, Kim Deane and Ken Hall.

The Commission staff is divided into three groups:

- **Information Services Group**

Consists of the Commission Secretary and the Information Services Group. The Commission Secretary acts as the official contact for both regulated utilities and the public. The department responds to all information requests (including Freedom of Information requests), prepares Annual Reports and quarterly Regulatory Updates, provides in-house computer services, media interaction, maintains the Commission's database of mailing lists, and library services. It also deals with utility customer complaints and operates and maintains the Commission's information resources.

- **Regulatory Affairs and Planning**

Consists of professional staff with expertise and experience in the areas of accounting, economics, ratemaking, and engineering. The regulatory affairs and planning functions of the Commission include the review of energy supply and demand, conservation, financial, accounting, social and economic impacts and the safety aspects of energy production, transmission, and distribution. In considering a matter under review by the Commission, staff have a responsibility to develop a full record of evidence. This often requires that staff be technical advisors to the Commission, and also provide external expert witnesses to testify at hearings.

- **Office of the Chairperson and Financial Administration**

Conducts background research and prepares decision support for management policies and decisions in areas such as personnel and financial management, budget preparation, internal policies, external relations with government, other agencies, utilities and the public. Also provides a range of administrative, financial and human resource services to the Commissioners and staff.

Following is a list of the Commission staff as of March 2003, their positions, and departments.

Office of the Chair and Financial Administration

Marilyn E. Donn	Assistant to the Chair and Manager, Financial Administration
Lisa D. Morris	Financial Assistant/Stenographer

Commission Secretary's Office and Information Services Group

Robert J. Pellatt	Commission Secretary
Constance M. Smith	Assistant Commission Secretary/ Administrator, Computer Services
Alison H. Cormack	Information Services Officer
Debra L. Frank	Stenographer
Yvonne M. Lapierre	Stenographer/Receptionist
Cecilia H. MacDonald	Stenographer/Receptionist

Regulatory Affairs and Planning

William J. Grant	Executive Director
Rose A. Tomen	Stenographer

Strategic Services

James W. Fraser	Manager
Eileen Cheng	Senior Economist
Rob B. Gorter	Senior Economist

Rates and Finance

Barry McKinlay	Manager
John J. Hague	Senior Financial Analyst
Philip W. Nakoneshny	Senior Financial Analyst

Engineering and Commodity Markets

J. Brian Williston	Manager
Robert W. Rerie	Senior Electrical Engineer
Robert N. Brownell	Senior Commodities Analyst

Highlights, Accomplishments and Anticipated Events

2002/03 Regulatory Highlights

Regulatory proceedings before the Commission included:

- CENTRA GAS BRITISH COLUMBIA INC. - 2003 Revenue Requirements (Negotiated Settlement to Order No. G-2-03 dated January 9, 2003)
- CENTRA GAS WHISTLER INC. - 2003 Revenue Requirements (Negotiated Settlement to Order No. G-26-03 dated April 17, 2003)
- BRITISH COLUMBIA HYDRO AND POWER AUTHORITY - Application by the Office & Professional Employees' International Union, Local 378 regarding British Columbia Hydro and Power Authority - Proposed Consolidation, Amalgamation or Merger (Sections 52, 53 and 72) (Order No. G-28-02; Reasons for Decision)
- BC GAS UTILITY LTD. - 2003 Revenue Requirements (Decision dated February 4, 2003; Order No. G-7-03)
- BC GAS UTILITY LTD. - Disposition of Property and Approval of Customer Care Agreements (Order No. G-29-02; Reasons for Decision)
- UTILICORP NETWORKS CANADA (BRITISH COLUMBIA) LTD. - Complaint re: Brilliant Power Purchase Agreement (Letter No. L-18-02; Reasons for Decision)
- PRINCETON LIGHT AND POWER COMPANY, LIMITED - 2002/03 Revenue Requirements (Decision dated May 16, 2002; Order No. G-36-02)
- AQUILA CANADA NETWORKS (BRITISH COLUMBIA) LTD. - Final Routing, Cost Estimate and Agreements for the Kootenay 230 kV System Development Project (Order No. G-46-02; Reasons for Decision)
- AQUILA CANADA NETWORKS (BRITISH COLUMBIA) LTD. - 2003 Revenue Requirements (Negotiated Settlement to Order No. G-10-03 dated February 17, 2003)
- OFFICE & PROFESSIONAL EMPLOYEES' INTERNATIONAL UNION, LOCAL 378 - Application for Reconsideration of Commission Order No. G-28-02 and Reasons for Decision dated April 17, 2002 (Order No. G-48-02; Reasons for Decision)
- PACIFIC NORTHERN GAS LTD. - 2003 Revenue Requirements (Negotiated Settlement to Order No. G-14-03 dated March 11, 2003)
- PACIFIC NORTHERN GAS (N.E.) LTD. - 2003 Revenue Requirements (Order No. G-22-03; Reasons for Decision)

- PACIFIC NORTHERN GAS LTD. and PACIFIC NORTHERN GAS (N.E.) LTD. - Application for Reconsideration of Commission Order No. G-56-02 and Commission Decision dated July 31, 2002; and Application for Reconsideration of Order No. G-57-02 and Reasons for Decision (Order No. G-77-02; Reasons for Decision)

- EUROCAN PULP AND PAPER COMPANY - Pacific Northern Gas Ltd. / 2002 Revenue Requirements - Application for Reconsideration of Commission Order No. G-56-02 andCommission Decision dated July 31, 2002 (Order No. G-78-02; Reasons for Decision)

Brief summaries of the above-noted decisions and others may be found commencing on page 50 of this Report.

Electricity Market Developments

Over the last few years the Commission has been implementing demand response programs and competitive options into the electricity markets to enable utilities and some customers to reduce their electricity costs and to respond to opportunities for electricity trade with United States customers. BC Hydro provides wholesale transmission access, real time pricing tariffs and an opportunity for industrial customers to participate in curtailment programs to take advantage of high electricity market prices elsewhere. Aquila was the first utility in Canada to offer both wholesale and retail access to large industrial and municipal customers. Aquila also offers a green power rate and time-of-use rates.

In November 2002 the government issued its new energy policy, "Energy For Our Future: A Plan For BC." The four cornerstones of the policy are low electricity rates and public ownership of BC Hydro, secure reliable supply, more private sector opportunities, and environmental responsibility and no nuclear power sources. Sixteen of the 26 policy actions involve the Commission, including the strengthening of the Commission's mandate and the re-regulation of BC Hydro. On March 25, 2003, Order in Council 0253 was issued instructing the Commission to conduct an Inquiry into a Heritage Contract for BC Hydro's existing generation resources and Stepped Rate and Transmission Access for customers served at transmission voltage.

Alternative Dispute Resolution/Negotiated Settlement Process

The Commission's Negotiated Settlement Process: Policy, Procedures and Guidelines ("NSP Guidelines"), first issued in January 1996, sets the framework for utilities, intervenors, Commission staff and Commissioners in reviewing applications, attempting to achieve negotiated agreements, and the approval, amendment or rejection of a settlement agreement by a panel of Commissioners.

Since issuing its NSP Guidelines, the Commission has reviewed many settlement agreements arising out of successful negotiation processes. The Commission also established hearings to review applications or outstanding issues that were not successfully resolved through NSP.

Following a written review process, which concluded in early January 2000, revised NSP Guidelines were issued in January 2001 (Letter No. L-3-01).

Return on Common Equity ("ROE") Mechanism

Eight years ago the Commission initiated Canada's first automatic adjustment mechanism for utility ROEs. This mechanism was revised in 1997 and again in 1999. One of the inputs into the ROE mechanism is the average spread between 10- and 30-year yields on Government of Canada bonds during the month of October. Yields on 30-year bonds have traditionally been higher than yields on 10-year bonds such that the yield spread adjustment typically increased the ROE. The formula would not be applied if the forecasted long Canada Bond yields fell below 6.0 percent. Based on the 1999 amended mechanism, the 2003 ROE for a low risk benchmark utility was set at 9.42 percent.

The ROE for most of the larger regulated utilities continues to be set using the automatic adjustment mechanism. The mechanism appears to have general support from utilities and customer groups as being a fair and efficient method of setting the ROE. As the risk profile of any given utility may change over time, the risk premium for a specific utility may be reviewed and amended, usually as part of a revenue requirements review for that utility.

Incentive Regulation

The Commission has been a pioneer in the development of incentive regulation in Canada. It continues to refine its multi-year performance-based rate ("PBR") processes. The 2003 revenue requirements Decision for BC Gas noted many potential benefits of PBR, including lower rates and higher service quality for ratepayers and enhanced earnings potential for shareholders. That Decision also recognized the value of periodic oral public hearings to rebase the costs of the utility and to deal with structural issues.

British Columbia Hydro and Power Authority

Re-regulation of BC Hydro Rates

The BC Hydro rate freeze ended on March 31, 2003 and BC Hydro's rates will again be regulated to cover the projected costs of electricity to consumers. The Commission has instituted transmission access principles and tariffs for BC Hydro to allow this utility to participate in regional electricity markets.

Reports on Export Trade

Electricity markets have changed dramatically in recent years and BC Hydro's electricity trade activities are very important to the welfare of ratepayers. The continuing need for, and suggested changes to, Special Direction No. 8 are expected to be reviewed through the Heritage Contract inquiry process, which will precede the revenue requirements application. BC Hydro files quarterly reports on export trade, which enables the Commission to monitor activities on behalf of ratepayers.

Georgia Strait Natural Gas Pipeline Crossing

BC Hydro and Williams Gas Pipeline Company propose to build a natural gas pipeline from Sumas to Cherry Point, Washington and then crossing underwater to Vancouver Island ("GSX pipeline"). The pipeline would reach Vancouver Island south of Duncan and connect with the Terasen Gas (Vancouver Island) pipeline near Shawnigan Lake.

The Canadian portion of the GSX pipeline is under Federal jurisdiction and subject to the National Energy Board Act and the Canadian Environmental Assessment Act ("CEAA"). It has been referred to a Joint Review Panel for review under the CEAA. Approvals from the British Columbia Utilities Commission will be needed for Terasen Vancouver Island to connect to the GSX pipeline, for Terasen Vancouver Island rates to transport gas received from the pipeline, and for BC Hydro rates that may include expenditures related to the GSX pipeline.

The Joint Review Panel hearing is now concluded and a Decision is anticipated in the fall of 2003.

The NEB's web site is *http://www.neb-one.gc.ca*.

Certificate of Public Convenience and Necessity Application
for the Vancouver Island Generation Project ("VIGP")

BC Hydro applied on March 12, 2003 for a CPCN to construct and operate a natural gas generating plant at Duke Point, Vancouver Island. The VIGP would be a 265 MW electric generation plant to be served with natural gas from the GSX pipeline. The Commission established an oral public hearing to review the application. The hearing commenced in Nanaimo on June 16, 2003.

BC Gas Utility Ltd. / Terasen Gas Inc.

2003 Revenue Requirements Application

On June 17, 2002, BC Gas filed a 2003 Revenue Requirements and Multi-Year Performance-based ratemaking application to be resolved through a negotiated settlement process ("NSP"). Intervenors opposed the NSP, recognizing that it had been nearly 10-years since BC Gas' revenue requirements had been reviewed in an oral public hearing. The Commission ordered the review of the 2003 revenue requirements to an oral public hearing and noted the establishment of a 2003 base year would allow for an efficient NSP on a future multi-year performance-based application for 2004 and beyond. The Commission's Decision on February 4, 2003 established the base costs and dealt with several structural issues including depreciation rates, separation of the utility from BC Gas Inc., and code of conduct/transfer pricing issues.

Agent Billing and Collection for Transportation Service

Implementation of ABC-T service would provide Terasen Gas' residential and small commercial customers with the choice of buying gas from non-utility suppliers. Terasen Gas filed its "Commodity Unbundling and Customer Choice Report" dated February 28, 2003. The Report describes unbundling for both residential (RS-1) and commercial (RS-2 and RS-3) customers for November 1, 2004 using the Essential Services Model. A Commission Workshop was held in April 2003 to discuss options for the implementation of customer choice. The Commission decided to proceed with the Commercial Unbundling program based on the Essential Services Model along with a stable rate alternative for the residential class (Letter No. L-14-03). This intermediary step will assist the Commission in assessing customer response with the intention of proceeding to full unbundling for the residential class at a later date.

Amendments to the Utilities Commission Act were passed in May 2003 allowing the Commission to license and bond gas marketers.

Pacific Northern Gas Ltd.

2002 Revenue Requirements Applications and
Methanex Corporation's Application for a Load Retention Rate

On November 30, 2001, PNG and PNG (N.E.) applied for approval to recover increased revenue requirements associated with delivering natural gas. The Commission approved interim delivery charge increases and significant cost of gas decreases, which resulted in a net decrease in rates to sales customers (Order No. G-149-01).

The Commission issued both decisions on July 31, 2002. The PNG decision conditionally approved a Memorandum of Agreement between PNG and Methanex Corporation for new Firm Transportation Service Agreement for seven years commencing November 1, 2002. Adjustments in both the PNG and PNG (N.E.) decisions were expected to result in permanent 2002 rates for delivery charges that were lower than the 2002 interim rates. PNG and PNG (N.E.) were directed to file permanent 2002 rates and a method for refunding excess payments back to customers.

Rising Natural Gas Commodity Costs

The sharp increase in the continental market price for natural gas in the winter of 2000/01 abated somewhat in the 2001/02 heating season, but prices are expected to remain very volatile. Gas storage inventories were relatively high at the start of the 2002/03 heating season, but the impacts of production and supply variability, the strength of the economy, crude oil prices and weather remain major uncertainties. Prices remain high going to the 2003/04 fiscal year. Experience from the winter of 2001/02 demonstrated the significant impact of very high prices on consumers' cost of living and businesses' operating costs. There was a public expectation that regulators could somehow "save" consumers from high gas commodity costs, even though they have been set by market forces and passed on to the customers without mark-up by the utilities for over 15 years. Although the BCUC does not regulate the competitive market for the natural gas commodity, it has established mechanisms (i.e., Guidelines for Setting

Gas Recovery Rates and Managing the Gas Cost Reconciliation Balance) that tend to smooth out the fluctuations in gas costs so that British Columbia customers tend to pay less than the full gas cost when gas prices are high and pay slightly more than the actual cost when gas prices are low. In addition, the Commission reviews utility gas supply contracting and hedging plans to ensure that, within the limits of the forward market prices, the utilities purchase reliable supplies at the lowest cost possible. The Commission also reviews the status of deferral accounts to collect or refund variances between a gas utility's actual and forecast cost of gas.

Assistance to Yukon Utilities Board

Under a contract, Commission staff provided professional and technical services, assisting the Yukon Utilities Board with its regulatory proceedings.

Assistance to the Government of Saskatchewan

Under a contract, Commission staff prepared an independent report on proposed natural gas and revenue requirement increases of Sask Energy for review by a panel reporting to the Government of Saskatchewan.

2003/04 Anticipated Events

During the 2003/04 fiscal year the Commission will be responding to the following expected major applications:

- Vancouver Island Energy Corporation (BC Hydro) - Vancouver Island Generation Project at Duke Point (Oral Public Hearings in Nanaimo started June 16, 2003)
- BC Hydro - Heritage Contract Inquiry (Report and Recommendations to Cabinet on BC Hydro Heritage Contract - Workshops, Regional Meetings, Facilitated Negotiations, Pre-hearing Conferences, Public Hearings)
- BC Hydro 2004/05 Revenue Requirements Application
- Terasen Gas (formerly BC Gas Utility Ltd.) - 2004 and Multi-Year Revenue Requirements Application
- Terasen Gas (formerly BC Gas Utility Ltd.) – Agency, Billing and Transportation Service (ABC-T) Tariff (Gas Commodity Unbundling and Customer Choice - Small Commercial Phase 1, Residential Phase 2, Workshop on Business Rules, then Written Submissions)
- Aquila - 2004 and Multi-Year Revenue Requirements Application
- PNG – 2004 Revenue Requirement Application
- PNG (N.E.) – 2004 Revenue Requirement Application
- Terasen Whistler – 2004 Revenue Requirement Application
- B.C. Transmission Corporation Revenue Requirements
- ICBC 2004 Revenue Requirements and Rates for Compulsory Insurance

Supplementary Information

Regulated Utilities

Crown-Owned Electric Utility	*Service Area*
British Columbia Hydro and Power Authority 333 Dunsmuir Street Vancouver, BC V6B 5R3	Lower Mainland, Vancouver Island, Central and Northern BC and East Kootenay Regions

Investor-Owned Electric Utilities	Service Area
Hemlock Valley Electrical Services Limited 20955 Hemlock Valley Road Agassiz, BC V0M 1A1	Hemlock Valley
Princeton Light and Power Company, Limited Box 700 Princeton, BC V0X 1W0	Princeton, Osprey Lake and Missezula Lake Areas
Silversmith Power & Light Corporation Box 369 New Denver, BC V0G 1S0	Sandon, BC
Terasen Multi-Utility Services Inc. (formerly Sun Rivers Services Corp.) #1002 - 1708 Dolphin Avenue Kelowna, BC V1Y 9S4	Lot 152, CLSR Plan 78619 Kamloops IR No. 1
Aquila Networks Canada (British Columbia) Ltd. P.O. Box 130 Trail, BC V1R 4L4	West Kootenay and Okanagan Regions of BC
The Yukon Electrical Company Limited Box 4190 Whitehorse, Yukon Territory Y1A 3T4	Lower Post

Investor-Owned Natural Gas or Propane Utilities	*Service Area*
Terasen Gas Inc. (formerly BC Gas Utility Ltd.) 1111 West Georgia Street Vancouver, BC V6E 4M4	Lower Mainland, Fort Nelson, Central and Northern Interior, the Kootenays and the Okanagan
Terasen Gas (Vancouver Island) Inc. (formerly Centra Gas British Columbia Inc.) 1675 Douglas Street, P.O. Box 3777 Victoria, BC V8W 3V3	Sunshine Coast, Powell River, and Vancouver Island north to Campbell River, west to Port Alberni, and south to Victoria

Investor-Owned Natural Gas or Propane Utilities (continued)	*Service Area*
Terasen Gas (Whistler) Inc. (formerly Centra Gas Whistler Inc.) 1675 Douglas Street, P.O. Box 3777 Victoria, BC V8W 3V3	Whistler (Propane Grid System)
Pacific Northern Gas Ltd. #1400 - 1185 West Georgia Street Vancouver, BC V6E 4E6	Summit Lake to Prince Rupert and Kitimat
Pacific Northern Gas (N.E.) Ltd. #1400 - 1185 West Georgia Street Vancouver, BC V6E 4E6	Dawson Creek, Rolla, Pouce Coupe, Tumbler Ridge, Fort St. John
Pacific Northern Gas Ltd. #1400 - 1185 West Georgia Street Vancouver, BC V6E 4E6	Granisle (Propane Grid System)
Port Alice Gas Inc. #101 - 4381 Dawson Street Burnaby, BC V5C 4B4	Port Alice (Propane Grid System)
Stargas Utilities Ltd. P.O. Box 3002 Silver Star Mountain, BC V1B 3M1	Silver Star resort community
Terasen Gas (Squamish) Inc. (formerly Squamish Gas Co. Ltd.) 1111 West Georgia Street Vancouver, BC V6E 4M4	Squamish (Natural Gas)
Sun Peaks Utilities Co., Ltd. 1280 Alpine Road Sun Peaks, BC V0E 1Z1	Resort area north of Kamloops
Terasen Multi-Utility Services Inc. #1002 - 1708 Dolphin Avenue Kelowna, BC V1Y 9S4	Lot 152, CLSR Plan 78619 Kamloops IR No. 1
Toby Creek Utilities Co. Ltd. Panorama, BC V0A 1T0	Panorama

Investor-Owned Steam Heat Utility	*Service Area*
Central Heat Distribution Limited 720 Beatty Street Vancouver, BC V6B 2M1	Downtown Vancouver

Municipally-Owned Electric Utilities	*Service Area*

Only service outside of the Municipal boundaries is subject to regulation by the British Columbia Utilities Commission.

City of Grand Forks Box 220 Grand Forks, BC V0H 1H0	Grand Forks
City of Kelowna 1435 Water Street Kelowna, BC V1Y 1J4	Kelowna
City of Nelson (also known as Nelson Hydro) 502 Vernon Street Nelson, BC V1L 4E8	Nelson (urban and rural areas)
City of New Westminster 511 Royal Avenue New Westminster, BC V3L 1H9	New Westminster
City of Penticton 616 Okanagan Avenue East Penticton, BC V2A 3K6	Penticton
District of Summerland Box 159 Summerland, BC V0H 1Z0	Summerland

Domestic Electricity Sales - 2002

	Customers #	Revenue ($000)	Sales (GW.h)
CROWN-OWNED ELECTRIC UTILITY			
British Columbia Hydro and Power Authority	1,624,743	2,351,423	47,020.55
MUNICIPALLY-OWNED ELECTRIC UTILITIES			
City of Grand Forks	2,003	2,376	33.77
City of Kelowna	12,407	16,317	289.30
City of Nelson	9,080	9,291	156.20
City of New Westminster	28,613	22,338	391.52
City of Penticton	15,544	18,062	305.21
District of Summerland	5,141	4,858	81.04
Total Municipally-Owned	72,788	73,242	1,257.04
INVESTOR-OWNED ELECTRIC UTILITIES			
Aquila Networks Canada (British Columbia) Ltd.	89,611	116,981	1,999.00
Hemlock Valley Electrical Services Limited	201	229	0.96
Princeton Light and Power Company, Limited	3,159	4,380	62.71
Silversmith Light & Power Corporation	11	13	0.05
Terasen Multi-Utility Services Inc.	73	96	1.50
The Yukon Electrical Company Limited	84	120	0.75
Total Investor-Owned	93,139	121,819	2,064.97
TOTAL ALL ELECTRICAL UTILITIES	**1,790,670**	**2,546,484**	**50,342.56**

NOTES:

1. 1 gigawatt hour (GW.h) = 1 million kilowatt hours.

2. Figures reported are for the 2002 calendar year. Customers reported are as at December 31, 2002.

3. Revenues and sales for BC Hydro and Aquila Networks Canada (British Columbia) Ltd. (formerly known as UtiliCorp Networks Canada (British Columbia) Ltd. and West Kootenay Power Ltd.) are net of wholesale sales to other reporting electrical utilities identified in this table.

4. On April 25, 2003, Sun Rivers Services Corp. changed its name to Terasen Multi-Utility Services Inc.

Domestic Gas Sales - 2002

	Customers #	Revenue ($000)	Sales (GJ)(000)
INVESTOR-OWNED NATURAL GAS UTILITIES			
Terasen Gas Inc.			
Lower Mainland Division	538,771	901,259	127,874
Inland Division	208,637	267,468	55,395
Columbia Division	21,091	28,457	6,417
Fort Nelson Division	2,103	3,351	961
Terasen Gas (Squamish) Inc.	2,473	3,192	331
Terasen Gas (Vancouver Island) Inc.			
Vancouver Island, Powell River and Sunshine Coast areas	73,974	101,840	33,523
Pacific Northern Gas (N.E.) Ltd.			
Fort St. John Inc./Dawson Creek Division	15,096	26,609	4,653
Tumbler Ridge Division	1,132	1,505	727
Pacific Northern Gas Ltd.	22,853	80,053	34,067
Stargas Utilities Ltd.	161	440	29
Terasen Multi-Utility Services Inc.	61	17	1
TOTAL INVESTOR-OWNED	886,352	1,414,191	263,978
INVESTOR-OWNED PROPANE GRID SYSTEM UTILITIES			
Terasen Gas Inc. (Revelstoke)	1,444	2,612	226
Terasen Gas (Squamish) Inc.	36	39	2
Terasen Gas (Whistler) Inc.	2,159	8,263	695
Pacific Northern Gas Ltd.			
Granisle Grid	173	224	17
Port Alice Gas Inc.	250	335	18
Sun Peaks Utilities Co. Ltd.	441	936	62
Toby Creek Utilities Co. Ltd.	142	551	39
Total Propane Grid Systems	4,645	12,460	1,059
TOTAL ALL GAS UTILITIES	**890,997**	**1,427,151**	**265,037**

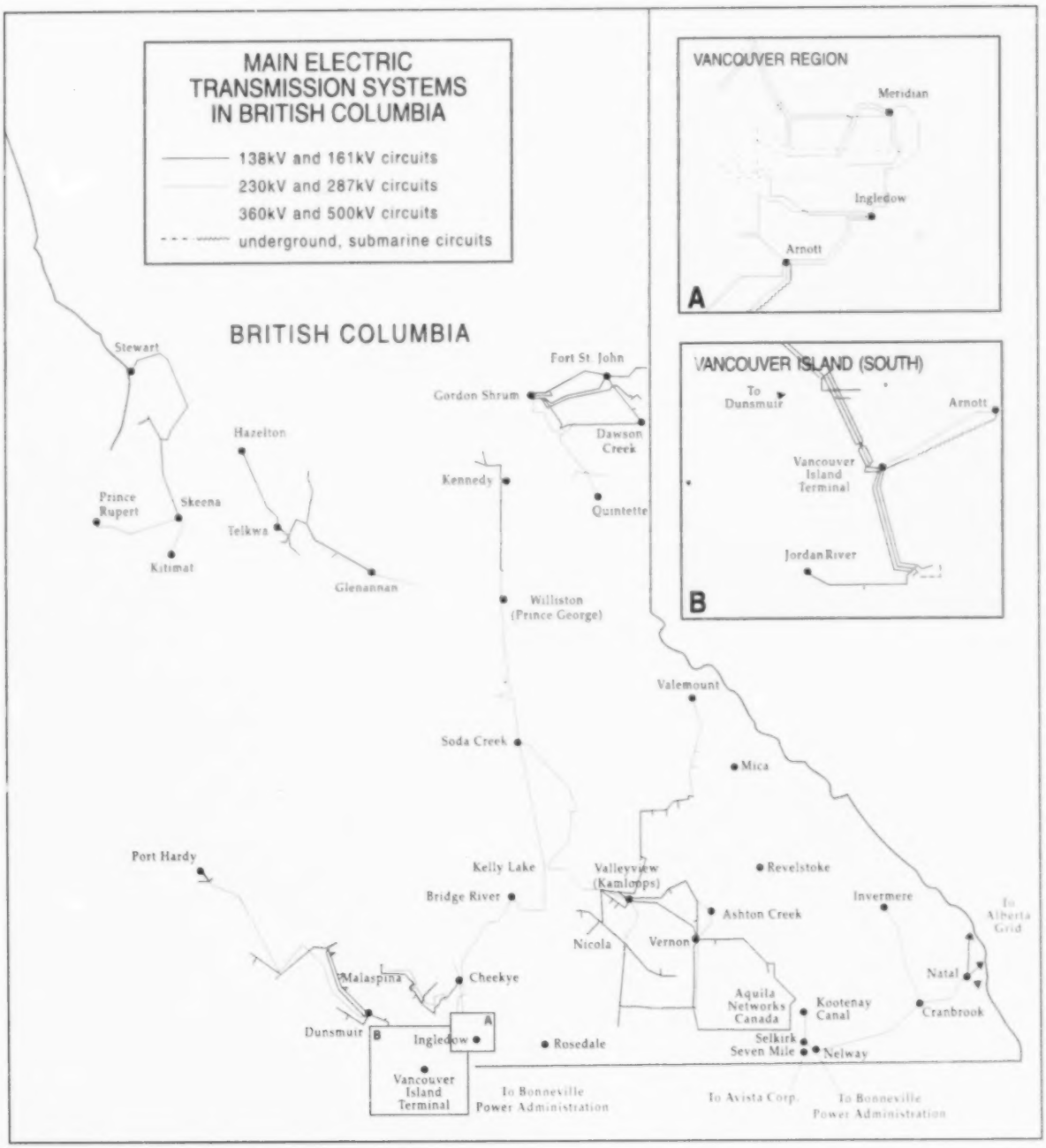
NOTES:

1. 1 gigajoule (GJ) is approximately equivalent to 0.910 mcf (mcf = one thousand cubic feet) or 0.0258 $10^3 m^3$ of natural gas or 0.376 mcf of propane vapour in L.P. gas grid systems.
2. Figures reported are for the 2002 calendar year. Customers reported are as at December 31, 2002.
3. Sales of GJ shown include sales to end-use customers plus gas owned by customers and transported to their industrial operations by utilities.
4. Revenues reported for natural gas utilities include only transportation margins for large industrial customers who have purchased gas supplies directly from producers or aggregators.
5. On April 25, 2003 BC Gas, Centra Gas, Sun Rivers and Squamish Gas changed their names to be known as Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Terasen Multi-Utility Services Inc. and Terasen Gas (Squamish) Inc.

Main Electric Transmission and Power Generating Facilities

Gas Utilities in British Columbia
LEGEND
Terasen Gas Inc.
Terasen Gas (Vancouver Island) Inc.
Duke Energy Gas Transmission Canada
TransCanada Pipelines Limited
Pacific Northern Gas Ltd./Pacific Northern Gas (N.E.) Ltd.
Communities served by Terasen Gas (Vancouver Island) Inc.
Communities served by Terasen Gas Inc.
Communities served by Pacific Northern Gas Ltd. / Pacific Northern Gas (N.E.) Ltd.
Port Alice served by Port Alice Gas Inc.
Sun Peaks served by Sun Peaks Utilities Co., Ltd.
Big White served by R334 Enterprises Ltd.
Silver Star served by Silver Star Mountain Resorts Utilities Ltd.
Sun Rivers served by Terasen Multi-Utility Services Inc.
Whistler served by Terasen Gas (Whistler) Inc.
Kicking Horse Mountain Resort served by Col-Gas Inc.
NOTES: Squamish Gas Co. Ltd. changed its name to Terasen Gas (Squamish) Inc. on April 25, 2003 and is a Terasen Inc. subsidiary. Duke Energy Gas Transmission Canada and TransCanada Pipelines Limited are regulated by the National Energy Board.
BRITISH COLUMBIA
Fort Nelson
Pink Mountain
Fort St. John
Hudson Hope
Chetwynd
Dawson Creek
Tumbler Ridge
Mackenzie
Granisle
Smithers
Terrace
Prince Rupert
Kitimat
Houston
Bear Lake
Burns Lake
Fort St. James
Summit Lake
Salmon Valley
Endako
Vanderhoof
Fraser Lake
Shelley
Endako Mines
Prince George
Hixon
Dunkley
Quesnel
Kersley
Williams Lake
150 Mile House
Lac La Hache
100 Mile House
Clinton
Cache Creek
Ashcroft
Port Alice
Campbell River
Courtenay
Comox
Powell River
Sechelt
Squamish
Whistler
Kingsvale
Parksville
Nanaimo
Port Alberni
Ladysmith
Duncan
Victoria
Vancouver
Princeton
Hedley
Huntingdon
Sicamous
Salmon Arm
Sorrento
Blind Bay
Spallumcheen
Grindrod
Chase
Sun Peaks
Sun Rivers
Kamloops
Armstrong
Enderby
Highland Valley
Logan Lake
Merritt
Westwold
Brenda Mines
Peachland
Westbank
Lakeview Heights
Oyama
Silver Star
Lumby
Coldstream
Vernon
Winfield
Big White
Kelowna
Naramata
Penticton
Okanagan Falls
Oliver
Osoyoos
Kaleden
Keremeos
Cawston
Princeton
Hedley
Summerland
Revelstoke
Kicking Horse Resort
Golden
Fernie
Elkford
Kimberley
Crestbrook
Sparwood
Cranbrook
Jaffray
Fort Steele
Byron Creek
Creston
Yahk
Galloway
Grand Forks
Christina Lake
Castlegar
Robson
Nelson
Salmo
Rossland
Trail
Montrose
Fruitvale
Midway
Greenwood
Boundary Falls
Rock Creek

Main Electric Transmission and Power Generating Facilities



Gas Utilities in British Columbia
LEGEND
Terasen Gas Inc
Terasen Gas (Vancouver Island) Inc
Duke Energy Gas Transmission Canada
TransCanada Pipelines Limited
Pacific Northern Gas Ltd / Pacific Northern Gas (N E) Ltd
Communities served by Terasen Gas (Vancouver Island) Inc
Communities served by Terasen Gas Inc
Communities served by Pacific Northern Gas Ltd / Pacific Northern Gas (N E) Ltd
Port Alice served by Port Alice Gas Inc
Sun Peaks served by Sun Peaks Utilities Co , Ltd
Big White served by R334 Enterprises Ltd
Silver Star served by Silver Star Mountain Resorts Utilities Ltd
Sun Rivers served by Terasen Multi Utility Services Inc
Whistler served by Terasen Gas (Whistler) Inc
Kicking Horse Mountain Resort served by Col Gas Inc
NOTES Squamish Gas Co Ltd changed its name to Terasen Gas (Squamish) Inc on April 25 2003 and is a Terasen Inc subsidiary Duke Energy Gas Transmission Canada and TransCanada Pipelines Limited are regulated by the National Energy Board
BRITISH COLUMBIA
Fort Nelson
Fort St. John
Hudson Hope
Chetwynd
Dawson Creek
Tumbler Ridge
Mackenzie
Bear Lake
Fort St. James
Summit Lake
Salmon Valley
Shelley
Dunkley
Williams Lake
150 Mile House
Lac La Hache
100 Mile House
Clinton
Cache Creek
Ashcroft
Sun Peaks
Clearwater
Sun Rivers
Kamloops
Kingsvale
Armstrong
Enderby
Port Alice
Highland Valley
Logan Lake
Merritt
Silver Star
Big White
Kelowna
Whistler
Powell River
Courtenay
Comox
Nanaimo
Parksville
Port Alberni
Ladysmith
Duncan
Victoria

Decisions, Reasons for Decision and Negotiated Settlements

As noted earlier, the Commission has moved from a calendar year to a fiscal year reporting period. Therefore, this summary covers 15 months from January 1, 2002 to March 31, 2003.

CENTRA GAS WHISTLER INC.

2002/03 Revenue Requirements Application

Negotiated Settlement appended to Order No. G-16-02 dated February 21, 2002

On November 15, 2001 Centra Whistler applied to decrease its commodity charge and adjust other utility charges on a permanent basis for January 1, 2002 and 2003. The Commission held a Workshop and Pre-hearing Conference on December 13, 2001 to discuss the Application together with a possible regulatory timetable. A Negotiated Settlement Process was held on February 6, 2002. On February 18, 2002 a proposed settlement agreement was agreed to by Centra Whistler, Intervenors and Commission staff.

By Order No. G-16-02 the Commission confirmed the settlement agreement and rate decrease effective January 1, 2002.

OFFICE OF PROFESSIONAL EMPLOYEES' INTERNATIONAL UNION, LOCAL 378

BC Hydro's Proposed Consolidation, Amalgamation or Merger

Reasons for Decision appended to Order No. G-28-02 dated April 17, 2002

On December 21, 2001 the Commission received a complaint on behalf of the Office of Professional Employees' International Union, Local 378 ("OPEIU") alleging that BC Hydro had violated, or was about to violate, Sections 52 and 53 of the Utilities Commission Act. The complaint contended that BC Hydro sought proposals from entities regarding joint venture/partnership arrangements to provide services currently provided by BC Hydro, which would involve the disposition of part of its property in violation of Section 52 of the Act. BC Hydro responded to the complaint, followed by a reply submission from the OPEIU. The Commission reviewed and considered the information before it.

The Commission issued Order No. G-28-02 and its Reasons for Decision denying the OPEIU's application and complaint.

BC Gas Utility Ltd.

Disposition of Utility Assets and Customer Care Agreements

Reasons for Decision appended to Order No. G-29-02 dated April 17, 2002

On December 24, 2001 BC Gas applied to transfer its Program Mercury and other customer care assets to BC Gas Inc. If approved, BC Gas Inc. intended to transfer those assets to a Limited Partnership with Enbridge Inc. identified as CustomerWorks. CustomerWorks would perform customer care services for BC Gas Utility Ltd. including call handling, billing, metering, payment processing, and credit and collections pursuant to a Client Services Agreement.

The Commission established a Written Public Hearing process and held a Workshop on January 29, 2002 to provide participants with a detailed review of the Customer Care Application and Douglas Louth Associates Inc.'s review of BC Gas' plans. BC Gas responded to submissions from intervenors on February 27, 2002.

By Order No. G-29-02 and Reasons for Decision, the Commission approved the disposition of the BC Gas Program Mercury and other customer care related assets to BC Gas Inc., effective December 31, 2001, in accordance with the Asset Transfer Agreement.

Approval was also given to two agreements with CustomerWorks, being a Client Services Agreement for the provision of customer care services and a Shared Services Agreement for the provision of corporate support services effective December 31, 2001. The Commission directed BC Gas to provide a Report and Recommendation for review prior to the renewal of contracts with CustomerWorks in 2007 or before committing to another service provider.

Aquila Networks Canada (British Columbia) Ltd.

Complaint regarding the 1996 Brilliant Power Purchase Agreement

Reasons for Decision appended to Letter No. L-18-02 dated May 2, 2002

Mr. Alan Wait complained to the Commission and asked for a reconsideration of the Commission's 1996 Decision that approved the Brilliant Power Purchase Agreement. The Commission outlined its reconsideration criteria to Mr. Wait in its acknowledgement letter. Following responses of Aquila Networks (formerly known as UtiliCorp Networks Canada and West Kootenay Power) and Columbia Power Corporation/CBT Energy the Commission reviewed the facts and issued Letter No. L-18-02 denying the complaint and the reconsideration of its 1996 Decision.

PRINCETON LIGHT AND POWER COMPANY, LIMITED

2002/03 Revenue Requirements Application and Holding Account for Contracting Activities
Decision dated May 16, 2002; Order No. G-36-02

PLP applied for approval of new Access and Service charges to become effective April 1, 2002 to cover the forecast shortfall in revenue for its fiscal year ending March 2003. Approval would result in an overall increase averaging 1.61 percent to ratepayers. On February 18, 2002 PLP filed an application for a Holding Account for Extraordinary Income and Expenses incurred from contracting activities.

On March 15, 2002 PLP filed a revised Application which corrected errors contained in the original filing and resulted in the revenue deficiency increasing to a total of $92,767. On March 28, 2002, the Commission issued Order No. G-22-02 approving an interim rate increase of between 4.4 percent and 5.15 percent to be applied across all rate classes and to Access and Service charges effective April 1, 2002, subject to refund following a written public hearing. There were no intervenors registered for the written public hearing process.

The Commission approved PLP's application to create a holding (deferral) account to record extraordinary income and expenses from its contracting activities, pursuant to the February 18, 2002 application.

The Commission issued Order No. G-36-02 confirming permanent rates for Service and Access Charges, pursuant to the Revised Application effective April 1, 2002.

AQUILA NETWORKS CANADA (BRITISH COLUMBIA) LTD.

Final Routing and Cost Estimates for Kootenay 230 kV System Development Project
Reasons for Decision appended to Order No. G-46-02 dated June 28, 2002

In 2000 the Commission issued a CPCN to Aquila for its Kootenay 230 kV System Development. The Certificate required Aquila to submit its final routing and cost estimates for the project, subject to certain modifications. In January 2002 Aquila filed its Final Project Routing, Schedule and Budget Estimates Report and held a Workshop in February 2002 in Castlegar, BC

The Commission issued its Decision on the final routing of the 230 kV Transmission Project and the Brilliant Terminal Station Facilities Interconnection and Investment Agreement on June 28, 2002.

OFFICE AND PROFESSIONAL EMPLOYEES' INTERNATIONAL UNION LOCAL 378

Application for Reconsideration of Order No. G-28-02 and Reasons for Decision
Reasons for Decision appended to Order No. G-48-02 dated July 11, 2002

On June 7, 2002 the OPEIU applied to the Commission to reconsider Order No. G-28-02 and Reasons for Decision.

The Commission established a written submission process to address whether the threshold for reconsideration has been met (Letter No. L-23-02). On June 21, 2002 BC Hydro provided its comments on the OPEIU request for reconsideration and, on June 29, 2002, the OPEIU responded.

By Order No. G-48-02 and Reasons for Decision, the Commission denied OPEIU's June 7, 2002 Reconsideration Application. The OPEIU's request for Leave to Appeal the Decision to the Court of Appeal was withdrawn on September 30, 2002 and formally abandoned on January 24, 2003 when the OPEIU filed a Notice of Abandonment in the Court of Appeal Registry.

PACIFIC NORTHERN GAS LTD.

2002 Revenue Requirements and Load Retention Rate to Methanex Corporation
Decision dated July 31, 2002; Order No. G-56-02

On November 30, 2001 PNG applied for approval to recover increased revenue requirements associated with delivering natural gas. PNG requested an increase in the gas delivery charge in residential rates of 13 to 16 percent and an increase in the gas delivery charge in small commercial rates of 12 to 16 percent to be effective January 1, 2002. The Commission approved interim delivery charge increases by Order No. G-149-01 and significant cost of gas decreases, which resulted in a net decrease in rates to sales customers.

On September 28, 2001 Methanex Corporation applied to the Commission for a load retention rate. Commission Order No. G-127-01 made the rates to Methanex interim effective October 1, 2001 and indicated that the Methanex Application would be reviewed coincident with PNG's 2002 Revenue Requirements Application.

At the conclusion of the hearing, the Commission set a timetable for final argument commencing on March 28, 2002. On March 20, 2002 PNG and Methanex entered into a Memorandum of Agreement ("MOA") to terminate their existing agreements for firm transportation and interruptible gas sales service and to enter into a new agreement effective November 1, 2002 through October 31, 2009 for firm take-or-pay service with an interruptible commodity charge. On March 27, 2002 PNG applied to postpone the filing of final argument to a date to be set by the Commission, and to fix a date for an oral hearing of the revised application reflecting the MOA, and to approve a revised hearing and argument schedule.

By Order No. G-20-02, the Commission postponed the filing of final argument and requested that intervenors respond by April 2, 2002 to whether they consent to PNG filing the revised application and their position on PNG's proposed timetable.

The Intervenor submissions raised additional issues and, by Commission Order No. G-23-02, the intervenors and PNG had to comment on these additional issues.

The Commission issued its decision on July 31, 2002. The PNG decision conditionally approved the MOA between PNG and Methanex Corporation that contemplated a new Firm Transportation Service Agreement for seven years commencing November 1, 2002. Adjustments in the PNG decision were expected to result in permanent 2002 rates for delivery charges that were lower than the 2002 interim rates. PNG was directed to file permanent 2002 rates and a method for refunding excess payments back to customers.

PACIFIC NORTHERN GAS (N.E.) LTD.

2002 Revenue Requirements Application

Reasons for Decision appended to Order No. G-57-02 dated July 31, 2002

On November 30, 2001 PNG (N.E.) applied for approval to recover increased revenue requirements associated with delivering natural gas. PNG (N.E.) requested an increase in the gas delivery charge in residential rates of 13 to 16 percent and an increase in the gas delivery charge in small commercial rates of 12 to 16 percent to be effective January 1, 2002. The Commission approved interim delivery charge increases by Order No. G-149-01 and significant cost of gas decreases, which resulted in a net decrease in rates to sales customers.

Commission Order No. G-4-02 approved a written hearing process for the PNG (N.E.) Application. The January 1, 2002 reductions in the commodity cost of gas component of rates for PNG were approved by Order No. G-136-01 and for PNG (N.E.) by Order No. G-137-01. Letter No. L-15-02 approved an extension to the deadlines established in the regulatory timetable.

On July 3, 2002 the Commission issued its Reasons for Decision attached as Appendix A to Order No. G-57-02.

AQUILA NETWORKS CANADA (BRITISH COLUMBIA) LTD.

Reconsideration Application of the Routing of the Kootenay 230 kV System Development Project
Letter No. L-34-02 dated September 6, 2002

Mr. Hans Karow requested the Commission reconsider its Order No. G-46-02 and Reasons for Decision into the Aquila Networks' application for approval of the Final Project Routing, Schedule and Budget Estimates for the Kootenay 230 kV System Development Project. The Commission reviewed the request and determined that Mr. Karow failed to provide evidence that the Commission made an error of material substance in its Decision. The Application for reconsideration was denied and the Commission issued Letter No. L-34-02.

PACIFIC NORTHERN GAS LTD. and PACIFIC NORTHERN GAS (N.E.) LTD.

Application for Reconsideration of Orders No. G-56-02 and G-57-02
Reasons for Decision appended to Order No. G-77-02 dated October 29, 2002

On August 22, 2002 PNG and PNG (N.E.) applied, pursuant to Section 99 of the Act, to have the Commission vary the Decisions in respect of the 2002 gas requirements forecasts for the residential and commercial customer classes for each service area (the "Reconsideration Application").

The Commission considered the PNG and PNG (N.E.) Reconsideration Applications and issued Order No. G-77-02 including Reasons for Decision attached as Appendix A to the Order.

EUROCAN PULP AND PAPER COMPANY

Application for Reconsideration of Order No. G-56-02
Reasons for Decision appended to Order No. G-78-02 dated October 29, 2002

On August 30, 2002 Eurocan Pulp and Paper Company ("Eurocan") applied, pursuant to Section 99 of the Act, to have the Commission reconsider and vary that portion of the Decision that allocates solely to PNG customers other than Methanex, the entire amount of the revenue deficiency arising out of the Memorandum of Agreement and from the closure of the Skeena Cellulose facilities (the "Reconsideration Application").

The Commission considered the Eurocan Reconsideration Application and issued Order No. G-78-02 including Reasons for Decision attached as Appendix A to the Order. The Commission determined that it will neither reconsider nor vary Order No. G-56-02 and the Decision that was issued concurrently with that Order. The Reconsideration Application was denied.

British Columbia Hydro and Power Authority

Certificate of Public Convenience and Necessity Application for 230 kV Project in Metro Vancouver
Reasons for Decision appended to Order No. C-14-02 dated December 17, 2002

BC Hydro applied for approval of a Certificate of Public Convenience and Necessity for a new 230 kV underground transmission line from the Horne Payne Substation to the Cathedral Square Substation in the downtown Vancouver core. The proposed route runs north from Horne Payne on Ingleton Avenue, west on William Street, north on Windermere Street, west on Pender Street, north on Vernon Drive, west on Cordova Street and south on Homer Street to Cathedral Square.

The Application stated that several of the electricity transmission cables that supply downtown Vancouver were approaching the end of their useful life, and a new transmission line was needed to maintain the reliability of electricity supply to the downtown core. The new circuit would also provide a seismically secure supply to the downtown core. The new line is estimated to cost $43.8 million, and is expected to be in service by May 2004.

The Commission reviewed the Application using a Written Public Hearing process. Commission Order No. C-14-02 approved a CPCN for the project.

Centra Gas British Columbia Inc.

Certificate of Public Convenience and Necessity Application to
Extend its Natural Gas Distribution System to Sooke, BC
Reasons for Decision appended to Order No. C-15-02 dated December 30, 2002

On November 7, 2002 Centra Gas filed its revised Application for a Certificate of Public Convenience and Necessity. On December 13, 2002 Centra Gas responded to an Information Request from Commission staff and filed a draft Natural Gas Pipeline Corridor License Agreement with the BC Transportation Financing Authority for the use of the Galloping Goose right-of-way for 20 years.

The Commission reviewed the Application and other submissions and approved the Application by Order No. C-15-02 and Reasons for Decision.

CENTRA GAS BRITISH COLUMBIA INC.

2003-2005 Revenue Requirements Application (Phase 1) and 2002 Rate Design Application (Phase 2)
Negotiated Settlement appended to Order No. G-2-03 dated January 9, 2003
Decision dated June 5, 2003; Order No. G-42-03

On July 31, 2002 Centra Gas filed its 2003 to 2005 Revenue Requirements Application requesting approval of actual revenue deficiencies and forecast test period cost of service. The Application was Phase 1 of a two-phase process to establish Centra Gas' cost of service for the future test period and to determine rates effective January 1, 2003 that are appropriate for the recovery of both the current cost of service and the amortization of accumulated revenue deficiencies. Centra Gas filed its Phase 2 Rate Design Application on September 30, 2002.

Centra Gas proposed that both the Phase 1 and 2 Applications be reviewed concurrently. On September 5, 2002 the Commission agreed in principle to this proposal. On October 22, 2002 participants at the Pre-hearing Conference were advised of the regulatory review options and did not oppose the establishing of a Negotiated Settlement Process for both the Phase 1 and Phase 2 Applications. Participants in the Negotiated Settlement Process for the Phase 1 Application met on November 25 and 26, 2002 and reached a Settlement Agreement, which was approved by the Commission on January 14, 2003.

The Centra Gas Phase 2 Rate Design application proceeded to a public hearing that was held on February 5, 7 and March 3 to 6, 2003 in Vancouver, BC The Decision was issued on June 5, 2003 and will be reported in the Commission's 2003/04 Report.

CENTRAL HEAT DISTRIBUTION LIMITED

Application for 2003 Revenue Requirements
Negotiated Settlement appended to Order No. G-4-03 dated January 16, 2003
Rates amended by Order No. G-8-03 dated February 3, 2003

On October 31, 2002 Central Heat filed its application to increase its Steam Tariff Schedule of Charges by 6.4 percent effective January 1, 2003.

Order No. G-101-02 set the current Central Heat rates as interim effective January 1, 2003, and established a Negotiated Settlement Process for the review of the revised application.

Order No. G-4-03 approved the Negotiated Settlement and an average permanent rate increase of 4.36 percent effective January 1, 2003 for Central Heat to recover a 2003 revenue deficiency of $243,929.

On January 31, 2003 Central Heat applied for an amendment to the approved 2003 rates to reflect an updated actuarial assessment of the Utility's pension plan. The amendment would increase the 2003 revenue deficiency to $303,829 for an average rate increase of 5.432 percent.

By Order No. G-8-03 the Commission approved an amendment of $59,900 to the pension expense forecast in the 2003 Negotiated Settlement and for Central Heat to recover a 2003 revenue deficiency of $303,829, subject to receipt of a complaint within 60 days of the Order being issued.

BC Gas Utility Ltd.

2003 Revenue Requirements Application

Decision dated February 4, 2003; Order No. G-7-03

On June 17, 2002 BC Gas filed its 2003 Revenue Requirements and Multi-Year Performance-Based Ratemaking Application for approval to establish a revised Schedule of Rates on a permanent basis, effective January 1, 2003. BC Gas requested that the Commission endorse a Negotiated Settlement Process to deal with the Application.

The Commission established a Workshop and Pre-hearing Conference which was held on July 17, 2002 (Order No. G-40-02). Participants indicated that they preferred to make submissions on the desirability of a negotiated settlement or oral public hearing process for any or all components of the application after a series of information requests and responses.

Following review of the submissions, by Order No. G-63-02, the Commission set a Regulatory Timetable to deal with the 2003 Revenue Requirements portion of the Application culminating in an oral public hearing, which commenced on November 12 and concluded on November 21, 2002.

BC Gas filed written argument on December 2, 2002 and Intervenors filed written argument on December 9, 2002. BC Gas filed a reply to Intervenors' arguments on December 16, 2002.

Commission Order No. G-90-02 made the current BC Gas rates interim as of January 1, 2003.

The Commission issued its Decision on February 4, 2003. The increase in delivery rates approved effective March 1, 2003 resulted in a 1.5 percent increase in the basic and delivery charges, or an annual cost increase of approximately $17.00 for residential customers.

AQUILA NETWORKS CANADA (BRITISH COLUMBIA) LTD.

2002 Annual Review and 2003 Revenue Requirements Application

Negotiated Settlement appended to Order No. G-10-03 dated February 17, 2003

Under the terms of the 2000-2002 Settlement Agreement of Aquila's rates for electric service, the Commission holds an Annual Review of the operation of the settlement and proposed rate adjustments. On November 15, 2002 Aquila applied for a one year extension of the existing Negotiated Settlement Agreement. In support of this proposal, the Utility filed a Preliminary 2003 Revenue Requirements Application.

By Order No. G-83-02, the Commission approved a 5 percent interim rate increase effective January 1, 2003, subject to refund after a Negotiated Settlement Process to determine final rates for 2003.

A Negotiated Settlement Process was held on January 13–14, 2003 in Penticton and was circulated to all Registered Intervenors on January 31, 2003.

By Order No. G-10-03 the Commission approved the January 31, 2003 Negotiated Settlement with a 4.3 percent general increase in rates effective January 1, 2003.

PACIFIC NORTHERN GAS LTD.

2003 Revenue Requirements Application

Negotiated Settlement appended to Order No. G-14-03 dated March 11, 2003

On November 29, 2002 PNG applied for approval of its rates on an interim and final basis, effective January 1, 2003. The Application sought to recover increased revenue requirements associated with delivering natural gas and with the commodity cost of gas. The Application requested an increase in the gas delivery charge in residential rates of about 21 percent and an increase of about 20 percent in small commercial rates. PNG also applied for an increase in the gas commodity charges of about 25 percent.

By Order No. G-91-02 the Commission approved interim rate increases in the gas delivery charge of about 17 percent and in the gas commodity charges, including GCVA riders, of about 22 percent for residential and commercial customers effective January 1, 2003.

The Commission established a Negotiated Settlement Process held on February 12 and 13, 2003 with representatives from the BC Public Interest Advocacy Centre, Avista Energy, Alcan Primary Metal Group, West Fraser Timber Co. Ltd. and its Eurocan Division attending. A Negotiated Settlement was reached among the participants and circulated to all interested parties on February 21, 2003.

By Order No. G-14-03 the Commission approved the Negotiated Settlement package. The Negotiated Settlement resulted in the current interim rates being reduced effective January 1, 2003. Gas deliveries billed at the higher interim rates were to be rebilled at the lower negotiated settlement rates and customers will receive a refund with interest on a future bill. The refund for a typical residential customer is estimated to be about $10.00.

PACIFIC NORTHERN GAS (N.E.) LTD.

2003 Revenue Requirements for Fort St. John/Dawson Creek and Tumbler Ridge Divisions
Reasons for Decision appended to Order No. G-22-03 dated March 27, 2003

On November 29, 2002 (subsequently revised on February 24, 2003), PNG (N.E.) applied for approval of its rates on an interim and final basis, effective January 1, 2003. The Application sought to recover increased revenue requirements associated with delivering natural gas and with the commodity cost of gas. The Application requested an increase in the gas delivery charge in residential rates ranging from 5.6 to 43.8 percent and an increase in small commercial rates ranging from 4.5 to 40.8 percent. PNG (N.E.) also applied for an increase in gas commodity charges ranging from 53.4 to 57.8 percent.

On December 11, 2002 PNG (N.E.) filed its Fourth Quarter 2002 Report on Gas Supply Charges and proposed an increase in the GCVA rider for January 1, 2003, from $0.15/GJ to $0.30/GJ for Tumbler Ridge customers to amortize the debit balance in the Tumbler Ridge GCVA over two years.

By Order No. G-92-02 the Commission approved interim rate increases in the gas delivery charge ranging from 5.7 to19.4 percent for residential customers and ranging from 4.4 to 16.1 percent for small commercial customers effective January 1, 2003. The Commission also approved interim rate increases in gas commodity charges, including GCVA riders ranging from 22.4 to 33.2 percent.

The Commission established a written Public Hearing Process for the review of the Application. The written hearing process occurred. Order No. G-22-03 with Reasons for Decision was issued on March 27, 2003 and approved final rate increases for residential customers, ranging from 3.8 to 19.4 percent and from 2.9 to 16.1 percent for small commercial customers. The Order also approved increases in gas commodity charges, including GCVA riders ranging from 22.4 to 33.2 percent.

Exemptions

There are two types of exemptions from the provisions of the *Utilities Commission Act:* Section 22 Ministerial exemptions and Section 88 Commission exemptions.

Section 22-Ministerial Exemptions

Ministerial Order **M-22-0205** (M202, dated June 6, 2002) exempts persons who are not otherwise a public utility, and their equipment facilities, plants, projects or systems, from the provisions of Part 3 of the Utilities Commission Act (except Section 22) with respect to the production and sale of electricity to BC Hydro or Powerex.

Following this date the Independent Power Producers ("IPPs") were not required to seek Commission exemptions from public utility status so long as the power produced from the project was sold to BCH Hydro or Powerex.

Section 22 also enables the Minister to refer an exemption application to the Commission for review, or delegate the decision to the Commission.

Section 88 – Commission Exemptions

Commission exemptions may exempt a utility from any provision of the Act except for Part 2 and matters subject to Sections 22 and 71. Cabinet pre-approval is required. This section is often used to exempt upstream natural gas plants, pipelines, and related facilities from public utility status.

The Commission has developed a specific practice to issue Section 88 exemptions. First, the utility applies to the Commission for an exemption from regulation with respect to a particular activity, project, or agreement. If the Commission agrees with the application in principle and decides that an exemption will not jeopardize the public interest, it requests approval from Cabinet. By order of the Lieutenant Governor in Council, Cabinet formally approves the exemption. Finally, the Commission issues its own order granting an exemption under Section 88(3).

The following Commission exemptions from regulation were granted under Section 88(3) of the Act in 2002/03.

- **Synex Energy Resources Ltd.**
  Order No. G-12-02

Exempted Synex from the provisions of Part 3 of the Act, except Section 22, with respect to the McKelvie Creek Hydroelectric Project.

- **Furry Creek Power Ltd.**
  Order No. G-13-02

Exempted Furry Creek from the provisions of Part 3 of the Act, except Section 22, with respect to the Furry Creek Hydroelectric Project.

- **Furry Creek Power Ltd.**
  Order No. G-14-02

Exempted Synex from the provisions of Part 3 of the Act, except Section 22, with respect to the ZZ Creek (76145) Hydroelectric Project.

- **Westcoast Energy Inc.**
  Order No. G-58-02

Approved the transfer of exemption rights under Order No. G-58-91 from Westcoast Power Inc. to McMahon Power Holdings L.P. and varied the 1991 Order.

- **Westcoast Energy Inc.**
  Order No. G-68-02

Rescinded Order No. G-58-02 and varied Order No. G-58-91 by further amending the operative clause.

Performance Indicators

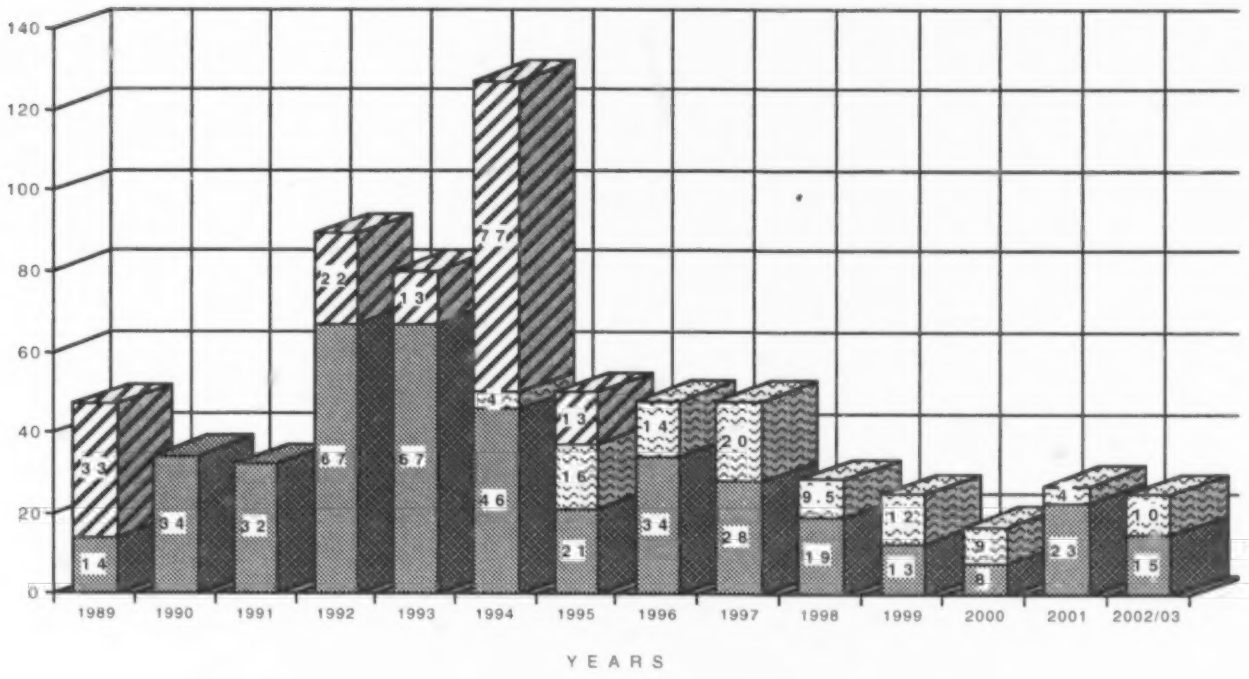
Proceeding Days Summary (Fiscal 2002/03)

Applicant	Application	Pre-hearing Conference	Workshop	NSP/ ADR	Oral Public Hearings	Total Days
PNG	2002 Revenue Requirements				1	1
PLP	2002/03 Revenue Requirements	Written Hearing				
BC Gas	2003 Revenue Requirements and Multi-Year Performance-Based Ratemaking Application	.5	.5		8	9
BC Gas	Lease Arrangements with the City of Vernon	Written Hearing				
Centra Gas	2003-2005 Revenue Requirements and 2002 Rate Design	.5	.5			1
	Phase 1-Revenue Requirements			3		3
	Phase 2-Rate Design			1	6	7
Stargas	Rate, Tariff and Ownership Changes	Written Hearing	1			1
BC Hydro	230 kV Underground Transmission Line from Horne Payne Substation to Cathedral Square Substation	Written Hearing				
CHDL	2003 Revenue Requirements			1		1
PNG	2003 Revenue Requirements		1	2		3
PNG (N.E.)	2003 Revenue Requirements	Written Hearing				
Aquila	Preliminary 2003 Revenue Requirements		1	2		3
Centra Whistler	2003 Revenue Requirements			1		1
TOTAL DAYS		**1**	**4**	**10**	**15**	**30**

Hearing and Alternative Dispute Resolution Days (Fiscal2002/03)

The Negotiated Settlement Process is part of the Commission's efforts to improve the quality and efficiency of regulation. Use of the Negotiated Settlement Process, which is also referred to as Alternative Dispute Resolution, requires considerable work before, during and after the negotiations. The Commission's revised "Negotiated Settlement Process: Policy, Procedures and Guidelines" were issued on January 23, 2001 (Letter No. L-3-01).

Alternative Dispute Resolution, the use of formulas for setting ROEs, and multi-year performance based settlements have all contributed to the decline in the number of hearing days (see chart). Matters referred to the Commission by the Lieutenant Governor in Council can have a dramatic affect on the number of hearing days; for example, in 1994 the Kemano Completion Project was reviewed over 77 hearing days.



Customer Complaints and Inquiries (Fiscal 2002/03)

Inquiries from Utility Customers concerning Terms and Conditions of Utility Service, Quality of Service, Rate Increases, Billing and Payment Requirements, Disconnections, etc.

An important aspect of the Commission's mandate is to apply regulation in a manner that reflects fair, consistent and clearly enunciated standards. Commission staff are available to assist the public in dealing with regulated utilities so that problems and inquiries are handled in a prompt, helpful and efficient manner.

Most complaints and inquiries are resolved through discussions between the customer and the utility concerned. Unresolved issues are referred to the Commission. To facilitate communication between the Commission and the customers of regulated utilities wishing to file complaints or have points clarified, toll-free calling from anywhere in the Province is available. The number of complaints and inquiries in 2002/03 decreased to 309 from 2,490 in 2001. Of the total number of complaints received, 112 complaints were associated with the continued fluctuation in the commodity cost of natural gas (down from 2,329 received in 2001).

To respond to customer calls, letters and inquiries regarding the cost of natural gas, the Commission prepared a detailed information package that helped explain why commodity charges for gas had increased. The package included a detailed letter explaining why the commodity cost of gas had not kept pace with decreases in the market price, a Backgrounder prepared by staff, and a comparative rates table for residential consumption. The information packages were also posted on the Commission's web site.

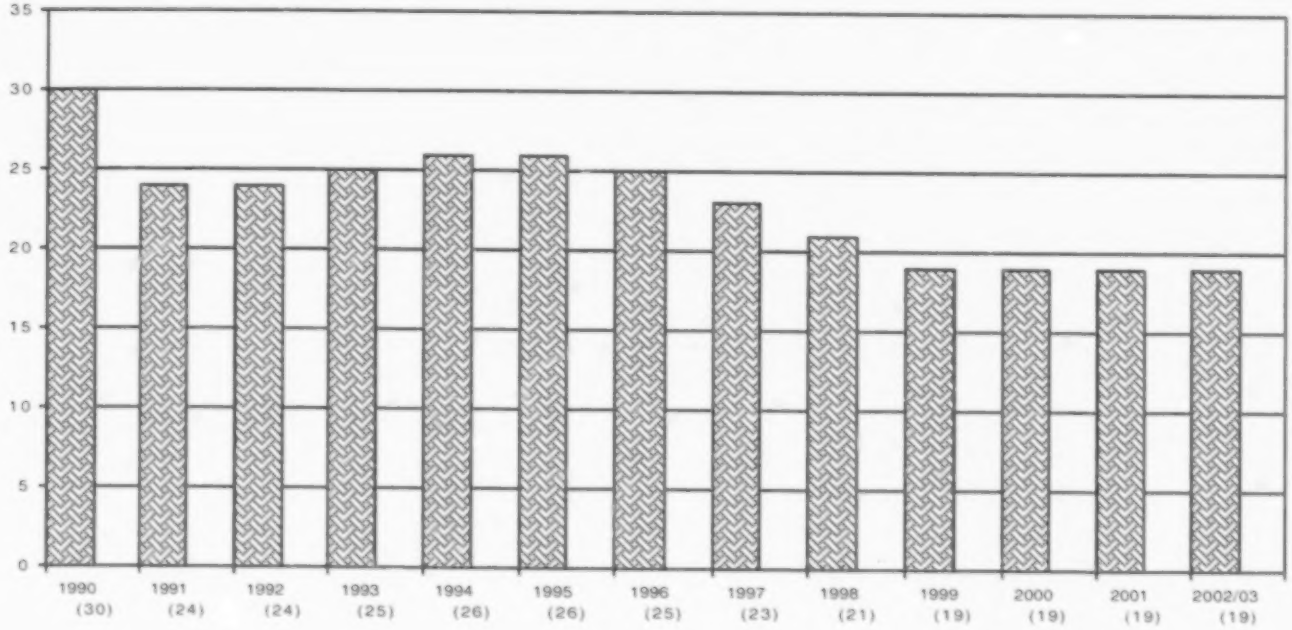
During 2002/03, two requests for information were made under the Freedom of Information and Protection of Privacy Act.

Summary of 2002/03 Customer Complaints and Inquiries

Gas Utilities		Total
BC Gas Utility Ltd.		
General Complaints	139	
Estimated Billing Complaints	14	
Rates & Basic Charge Complaints	19	
Cost of Gas Complaints:		
~ July 1, 2002	8	
~ October 1, 2002	13	
~ January 1, 2003	10	203
Centra Gas British Columbia Inc.		
General Complaints	11	
New Customer Rates (Cost of Gas) Complaints:		
~ January 1, 2003	33	44
Pacific Northern Gas Ltd.		
General Complaints		12
Pacific Northern Gas (N.E.) Ltd.		
General Complaints		8
Squamish Gas Co. Ltd.		1
Toby Creek Utilities Co. Ltd.		2
Sun Peaks Utilities Co.. Ltd.		1
Electric Utilities		
British Columbia Hydro and Power Authority		
General Complaints	44	
Proposed Consolidation, Amalgamation or Merger	14	58
British Columbia Hydro and Power Authority/BC Gas Utility Ltd.		
Complaints regarding transfer of BC Gas billing system		4
Aquila Networks Canada (British Columbia) Ltd.		
General Complaints	47	
Power Outages	6	53
Hemlock Valley Electrical Services Limited		3
Princeton Light & Power Company, Limited		1
Total 2002/03 Complaints/Inquiries		390

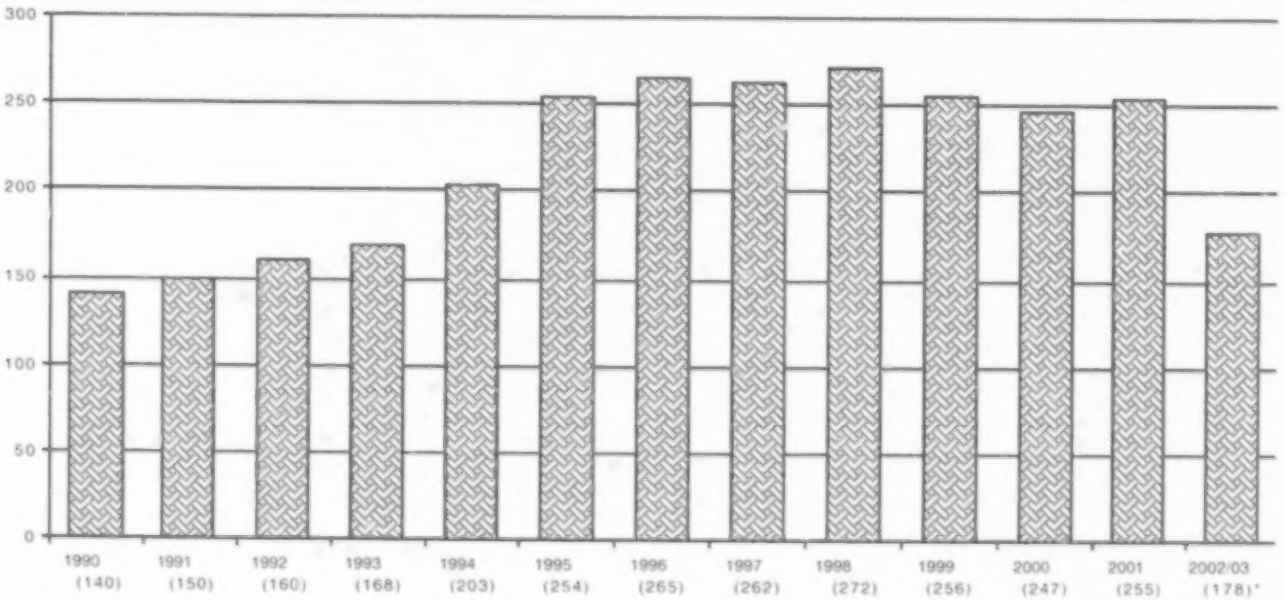
Staffing Levels

Staffing remained constant at 19 in 2002/03, largely unchanged over the last five years and down from 26 in the mid 1990s.



Directives Issued

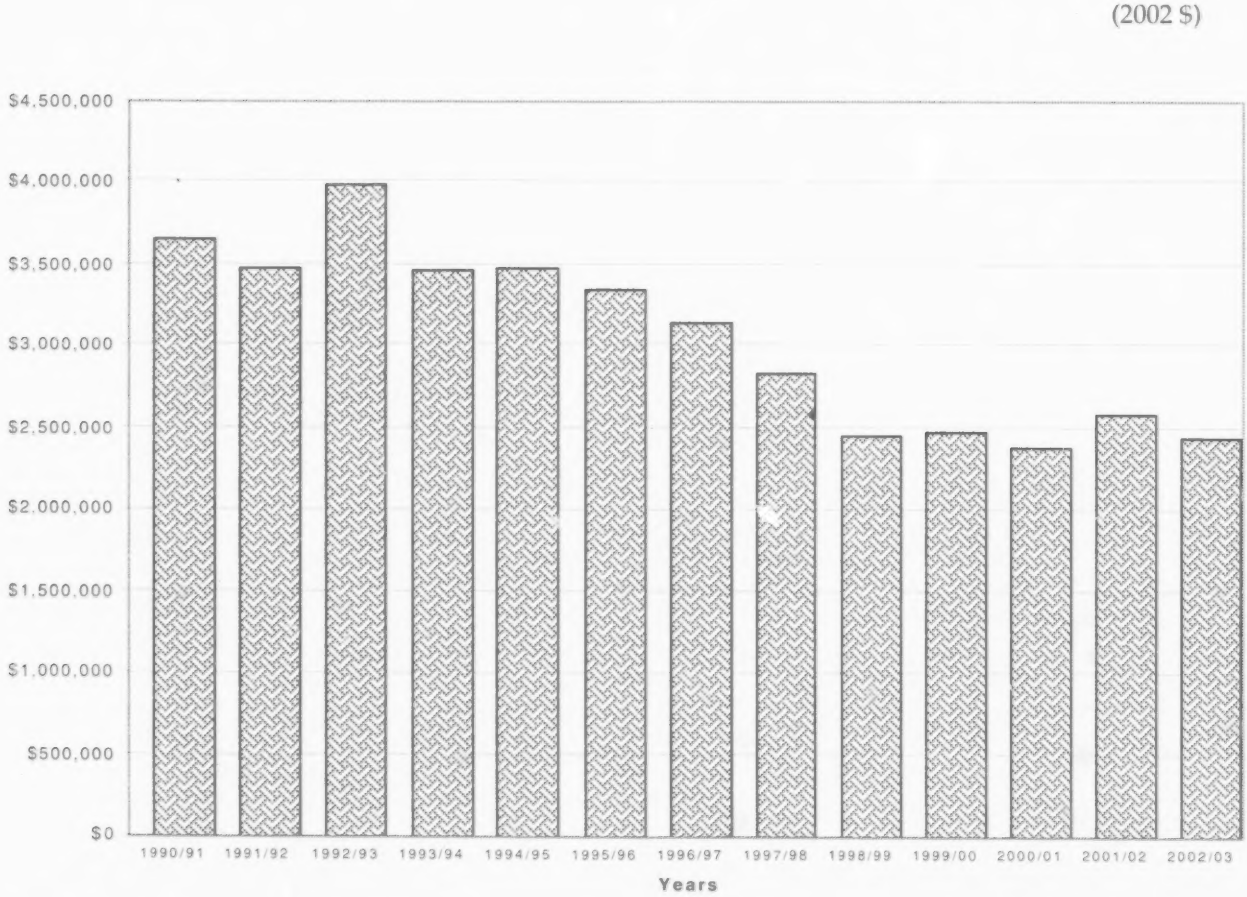
The number of Orders and Letters of Direction issued in 2002/03 was 178, down from the annual levels experienced since the mid 1990s.



* Reporting period covers April 1, 2002 thaough March 31, 2003

Commission Expenditures

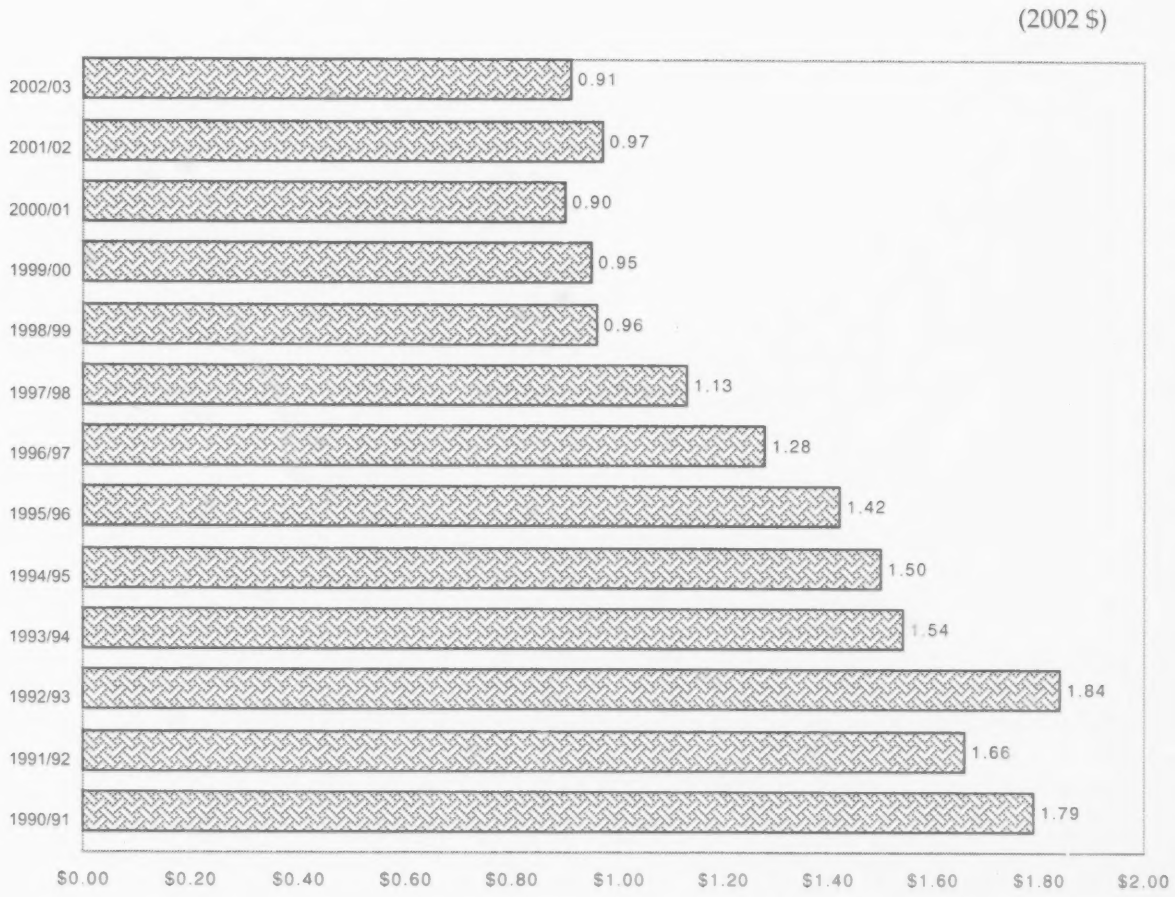
The Commission's actual expenditures for fiscal year 2002/03 (unaudited) were $2.445 million. Adjusted for inflation, Commission expenditures have been close to $2.5 million in each of the last five years. A summary of revenues and expenditures may be found on pages 29 to 31.



Commission Expenditures (2002$)

Cost of Regulation per Customer

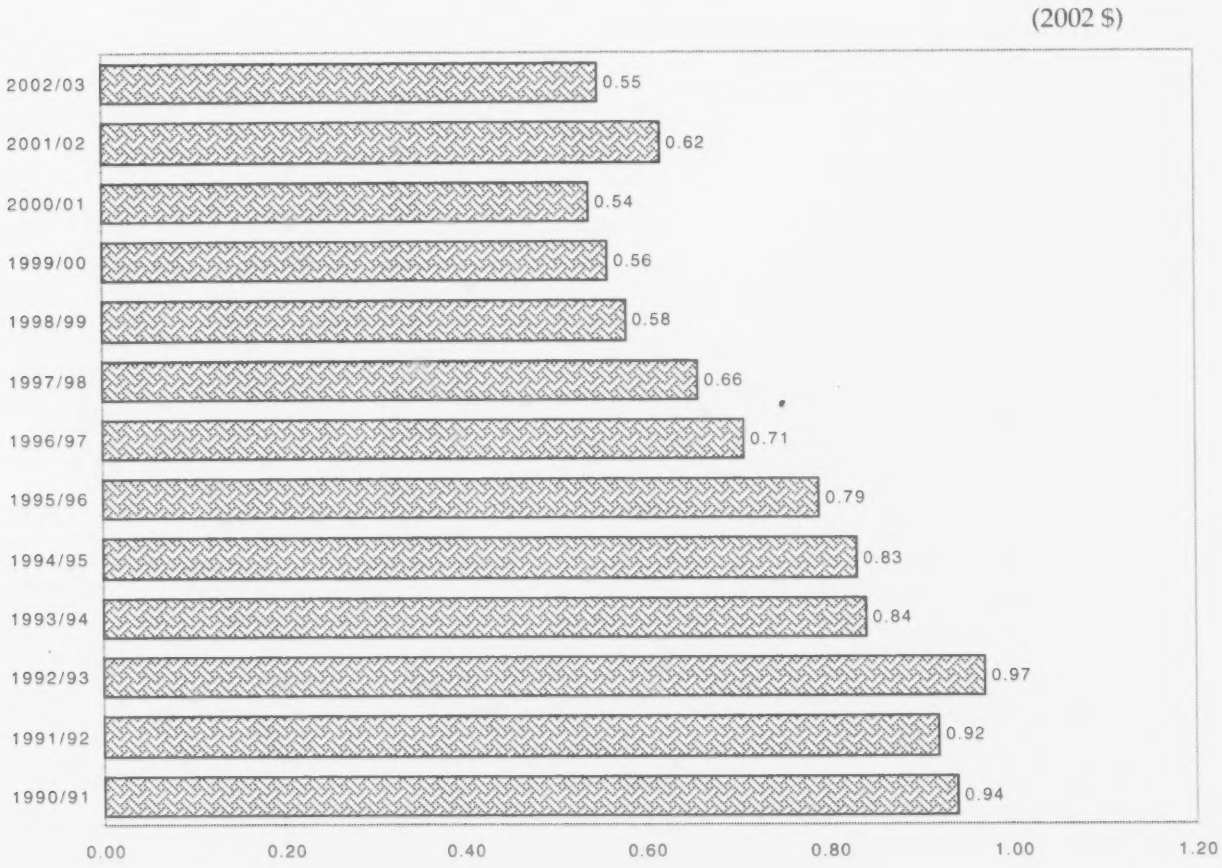
The cost of regulation per customer is calculated by dividing Commission expenditures by the total number of customers of regulated utilities. In each of the last five years, it has been under one dollar per customer, about half of what it was in the early 1990's.



Cost of Regulation per Customer (2002$)

Cost of Regulation per GJ of Energy Sold (cents)

The cost of regulation per gigajoule of energy sold is calculated by dividing Commission expenditures by the amount of energy sold or transported by utilities in that year. In recent years, it has ranged between half and two-thirds of a cent per gigajoule.



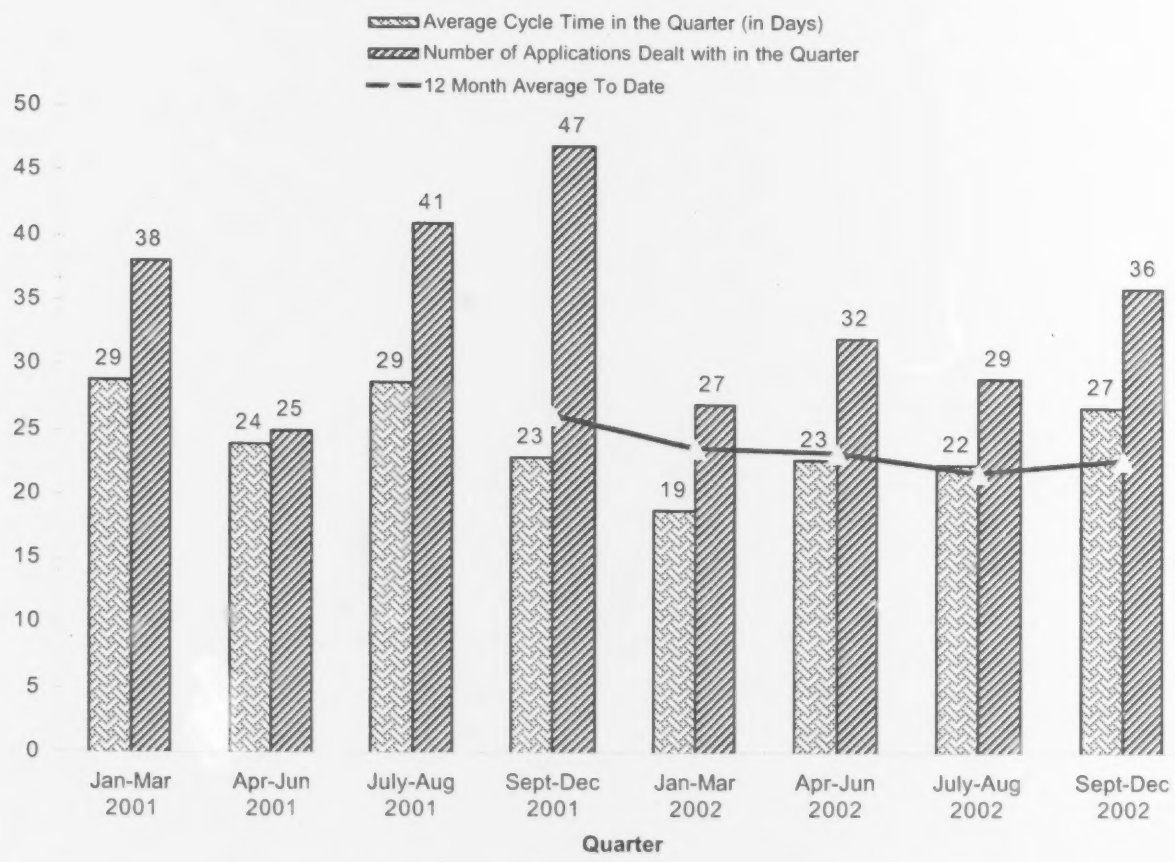
Cost of Regulation per GJ of Energy Sold (2002 cents)

Cycle Times

The following four graphs portray "cycle" or "turnaround" times — the time elapsed between the receipt of an Application and a Commission decision — categorized according to the four main ways the Commission processes the Application.

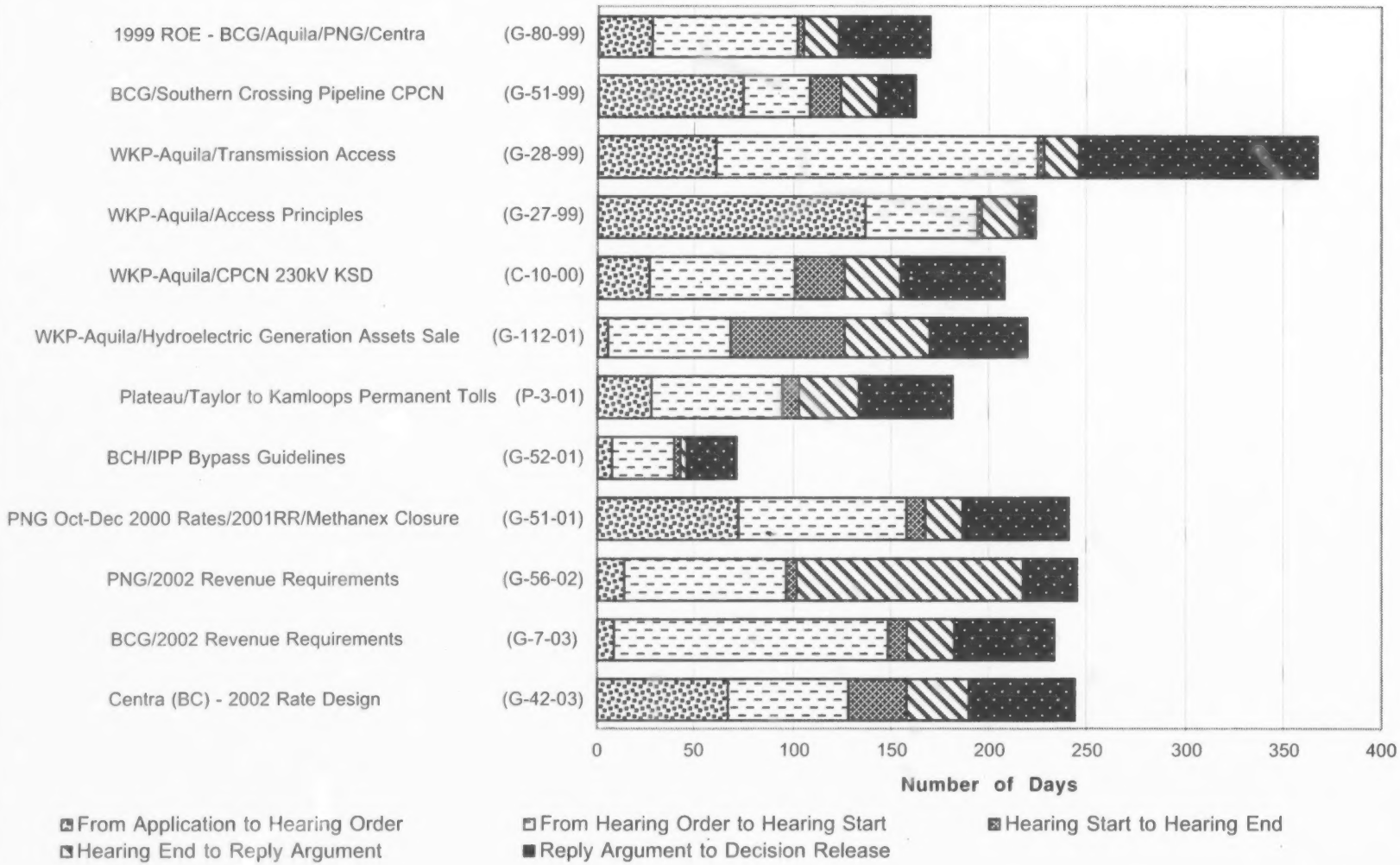
"Non-Hearing" Applications are usually straightforward and not controversial. They are managed by staff review and analysis, often with supplementary information requests and responses from the utility, but without a formal public review. Average cycle times, by quarter, ranged from 19 to 27 calendar days in 2002.

Cycle Times for Non-Hearing Applications by Quarter (2001-2002)

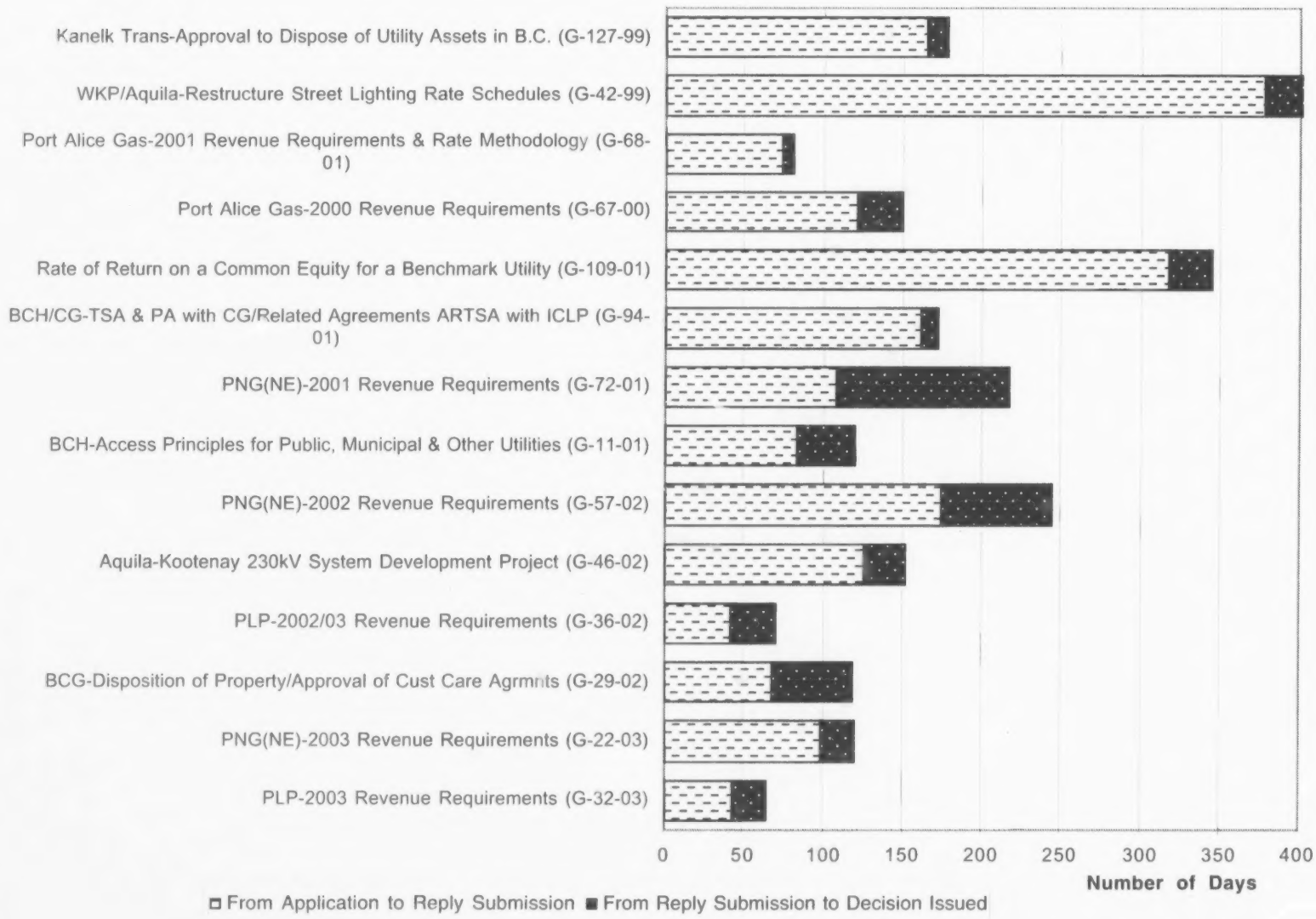


More complex applications require a public review process, usually through either an oral public hearing, a written public hearing, or a negotiated settlement process. The following three graphs portray the cycle times for applications since 1998/99 managed by these three processes. Oral public hearings are quasi-judicial and adversarial; most take seven to eight months between receipt of the Application and the issuance of the Commission Decision. The BCUC's written hearing process cycle times average about six months, and Applications managed by a negotiated settlement process take about four months on average between receipt and disposition.

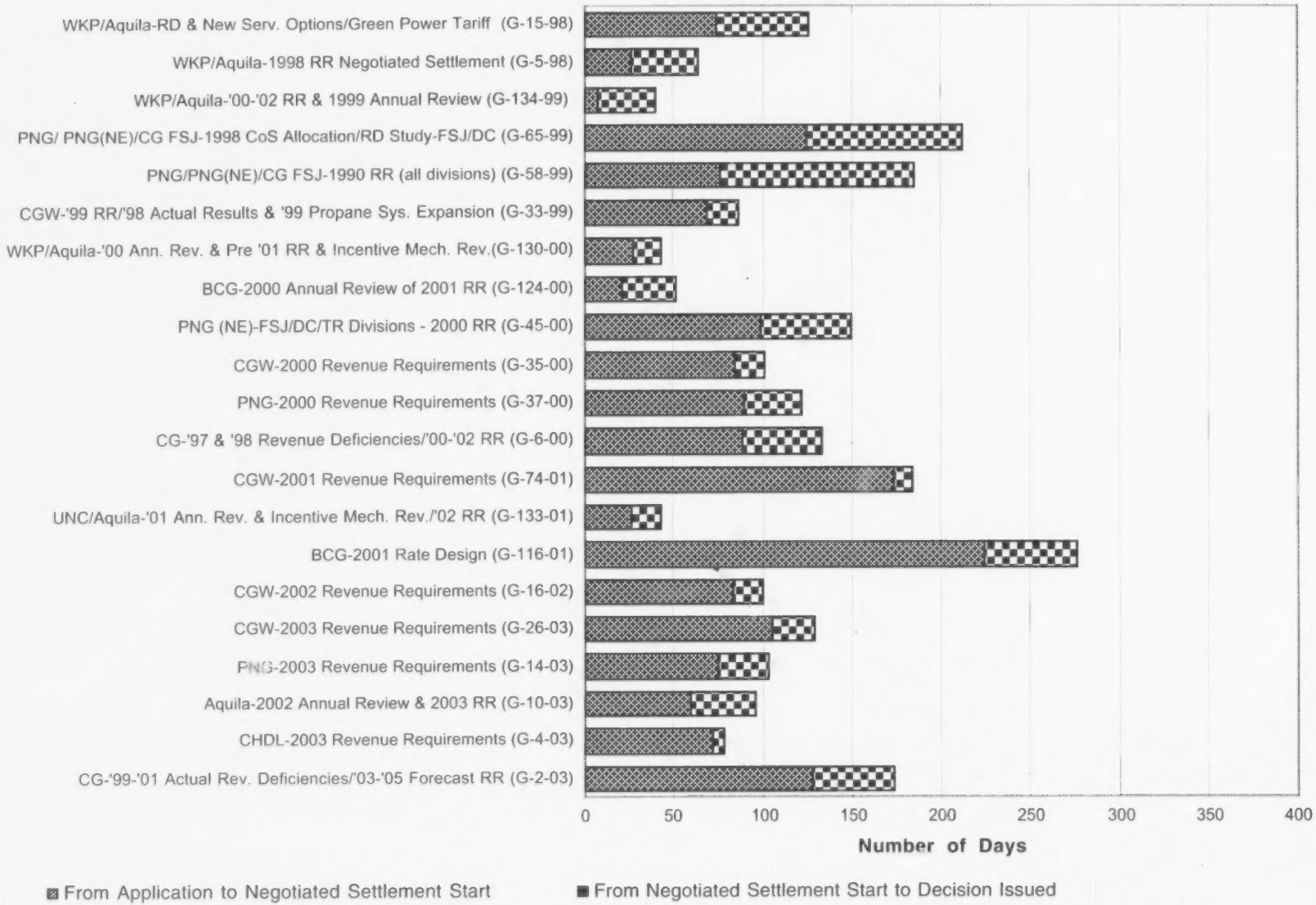
BCUC ORAL PUBLIC HEARING CYCLE TIMES 1998 to DATE



BCUC WRITTEN HEARING CYCLE TIMES 1998 to DATE


Kanelk Trans-Approval to Dispose of Utility Assets in B.C. (G-127-99)
WKP/Aquila-Restructure Street Lighting Rate Schedules (G-42-99)
Port Alice Gas-2001 Revenue Requirements & Rate Methodology (G-68-01)
Port Alice Gas-2000 Revenue Requirements (G-67-00)
Rate of Return on a Common Equity for a Benchmark Utility (G-109-01)
BCH/CG-TSA & PA with CG/Related Agreements ARTSA with ICLP (G-94-01)
PNG(NE)-2001 Revenue Requirements (G-72-01)
BCH-Access Principles for Public, Municipal & Other Utilities (G-11-01)
PNG(NE)-2002 Revenue Requirements (G-57-02)
Aquila-Kootenay 230kV System Development Project (G-46-02)
PLP-2002/03 Revenue Requirements (G-36-02)
BCG-Disposition of Property/Approval of Cust Care Agrmnts (G-29-02)
PNG(NE)-2003 Revenue Requirements (G-22-03)
PLP-2003 Revenue Requirements (G-32-03)
0
50
100
150
200
250
300
350
400
Number of Days
From Application to Reply Submission
From Reply Submission to Decision Issued

BCUC NEGOTIATED SETTLEMENT CYCLE TIMES 1998 to DATE


WKP/Aquila-RD & New Serv. Options/Green Power Tariff (G-15-98)
WKP/Aquila-1998 RR Negotiated Settlement (G-5-98)
WKP/Aquila-'00-'02 RR & 1999 Annual Review (G-134-99)
PNG/ PNG(NE)/CG FSJ-1998 CoS Allocation/RD Study-FSJ/DC (G-65-99)
PNG/PNG(NE)/CG FSJ-1990 RR (all divisions) (G-58-99)
CGW-'99 RR/'98 Actual Results & '99 Propane Sys. Expansion (G-33-99)
WKP/Aquila-'00 Ann. Rev. & Pre '01 RR & Incentive Mech. Rev.(G-130-00)
BCG-2000 Annual Review of 2001 RR (G-124-00)
PNG (NE)-FSJ/DC/TR Divisions - 2000 RR (G-45-00)
CGW-2000 Revenue Requirements (G-35-00)
PNG-2000 Revenue Requirements (G-37-00)
CG-'97 & '98 Revenue Deficiencies/'00-'02 RR (G-6-00)
CGW-2001 Revenue Requirements (G-74-01)
UNC/Aquila-'01 Ann. Rev. & Incentive Mech. Rev./'02 RR (G-133-01)
BCG-2001 Rate Design (G-116-01)
CGW-2002 Revenue Requirements (G-16-02)
CGW-2003 Revenue Requirements (G-26-03)
PNG-2003 Revenue Requirements (G-14-03)
Aquila-2002 Annual Review & 2003 RR (G-10-03)
CHDL-2003 Revenue Requirements (G-4-03)
CG-'99-'01 Actual Rev. Deficiencies/'03-'05 Forecast RR (G-2-03)
0
50
100
150
200
250
300
350
400
Number of Days
From Application to Negotiated Settlement Start
From Negotiated Settlement Start to Decision Issued

General Orders

The orders and letters described in the next four sections cover a 15-month period from January 1, 2002 to March 31, 2003. The *Utilities Commission Act* was amended in 2003 to change the reporting period from calendar year to fiscal year.

G-1-02 STARGAS

Approved a reduction of $0.643/GJ in rates for Residential and Commercial customers effective January 1, 2002.

G-2-02 BC GAS

Notice of Workshop and Written Public Hearing into the Disposition of Property and Customer Care Agreements Application.

G-3-02 CENTRA GAS

Approved the following decreases in rates effective February 1, 2002:

- Pioneer SGS-1 customers by 5.84 percent
- Pioneer SGS-2 customers by 7.33 percent
- ACR-1 customers in the Capital Regional District of between 3.92 to 7.24 percent
- ACR-1 customers in Other Communities consuming less than 6,000 GJ annually of between 5.28 to 6.50 percent.

G-4-02 PNG (N.E.)

Regulatory Agenda and Timetable setting out the key filing dates for the review of the 2002 Revenue Requirements Application.

G-5-02 CITY OF NELSON

Approved and accepted for filing Electrical Utility Amendment By-Law No. 2936, 2002 incorporating a 1.75 percent rate increase, effective February 1, 2002. The City is to file a certified copy of the By-Law following all approvals.

G-6-02 CENTRA GAS

Approved a decrease in rates for the following Pioneer SGS and LGS customers, effective March 1, 2002 as follows:

	Current Rate ($/GJ)	New Rate ($/GJ)	Percent Change (Decrease)
SGS-1	12.20	11.88	(2.62)
SGS-2	10.86	10.57	(2.67)
LGS-1	8.42	8.20	(2.61)
LGS-2	7.93	7.72	(2.65)
LGS-3	7.44	7.25	(2.55)
CRR-Top	7.44	7.25	(2.55)
CRR-Bottom	6.10	5.94	(2.62)

G-7-02 SUN RIVERS

Approved decreases in natural gas rates for Rate Schedule 1 - Residential Service and Rate Schedule 2 - Commercial Service customers, effective January 1, 2002.

G-8-02 BC GAS INC.

Approved, pursuant to Section 54 of the Act, the acquisition of a reviewable interest in the shares of Centra Gas British Columbia Inc. and Centra Gas Whistler Inc., subject to the consent of the Province of British Columbia, through amendments to the Vancouver Island Natural Gas Pipeline Act.

G-9-02 CENTRA GAS

Approved, pursuant to Section 54(5) of the Act, the registration of a transfer of the common and preferred shares to BC Gas Inc., subject to the consent of the Province of British Columbia, through amendments to the Vancouver Island Natural Gas Pipeline Act.

G-10-02 CENTRA WHISTLER

Approved, pursuant to Section 54(5) of the Act, the registration of a transfer of the common shares of Centra Whistler to BC Gas Inc.

G-11-02 ATCO ELECTRIC LTD.

Amended CPCN No. C-2-98 to include all additions and extensions, which may be required as part of the electrical service to Pioneer's Chinchaga area facilities.

Amended Order No. G-58-98 to exempt ATCO Electric from Part 3 of the Act, except Section 22, with respect to its electrical facilities required to serve Pioneer's Chinchaga area facilities.

Accepted, for filing the Memorandum of Agreement for the supply of service dated January 11, 2002, the application of the Alberta Energy and Utilities Board-approved Tariff D31 for the transportation of electricity, and the Alberta Energy and Utilities Board-approved tariff for the terms and conditions of Default Retailer Service and Supplier of Last Resort for the energy commodity, pursuant to Section 71 of the Act.

G-12-02 SYNEX ENERGY RESOURCES LTD.

Exempted Synex from the provisions of Part 3 of the Act, except Section 22, with respect to the McKelvie Creek Hydroelectric Project. BC Hydro is to file the Standard Electricity Purchase Agreement with Synex as an energy supply contract, pursuant to Sections 71 and 68 of the Act.

G-13-02 FURRY CREEK POWER LTD.

Exempted Furry Creek from the provisions of Part 3 of the Act, except Section 22, with respect to the Furry Creek Hydroelectric Project. BC Hydro is to file the Standard Electricity Purchase Agreement with Furry Creek Power Ltd. as an energy supply contract, pursuant to Sections 71 and 68 of the Act.

G-14-02 SYNEX ENERGY RESOURCES LTD.

Exempted Synex from the provisions of Part 3 of the Act, except Section 22, with respect to the ZZ Creek (76145) Hydroelectric Project. BC Hydro is to file the Standard Electricity Purchase Agreement with Synex as an energy supply contract, pursuant to Sections 71 and 68 of the Act.

G-15-02 BC GAS

Approved an extension to the expiry date of the NGV Service Agreement, Tariff Supplement No. C-1, with Beach Place Ventures Ltd. to August 15, 2002.

G-16-02 CENTRA WHISTLER

Approved the 2002/03 Revenue Requirements Settlement Agreement, which confirms the interim energy charge for all customers of $11.613/GJ, and a Gas Cost Deferral Account Rider of $0.987/GJ, effective January 1, 2002.

G-17-02 BC HYDRO

Directed BC Hydro to continue to allow Rate Schedule 1821 customers with idle self-generation capability to sell excess self-generated electricity, provided the self-generating customers do not arbitrage between embedded-cost utility service and market prices.

The conditions established under Order No. G-38-01 to prevent such arbitrage are to remain in effect until the Commission determines that future circumstances no longer justify the existence of such a program.

G-18-02 CENTRA GAS

Approved a decrease to the following ACR-1 customer rates effective April 1, 2002:

	Current Rate ($/GJ)	New Rate ($/GJ)	Percent Change (Decrease)
ACR-1 (Minimum Use)			
Capital Regional District			
ACR-1 (200)	8.58	8.07	(5.94)
ACR-1 (600)	7.81	7.29	(6.66)
ACR-1 (2000)	7.81	7.29	(6.66)
ACR-1 (6000)	7.81	7.29	(6.66)
Other Communities			
ACR-1 (200)	8.97	8.46	(5.69)
ACR-1 (600)	8.20	7.68	(6.34)
ACR-1 (2000)	8.20	7.68	(6.34)
ACR-1 (6000)	8.13	7.68	(5.54)

G-19-02 PNG AND PNG (N.E.)

Approved for PNG-West, effective April 1, 2002, a Gas Cost Variance Account credit rider and a reduction in the Company Use Gas charge that are calculated to repay the end of February 2002 GCVA credit balances over the next 12 months of deliveries.

Accepted PNG-West's recommendation that current propane rates for Granisle customers continue unchanged, effective April 1, 2002.

Accepted PNG (N.E.)'s recommendation that the current Gas Supply Charges and GCVA riders continue unchanged, effective April 1, 2002, for Fort St. John, Dawson Creek and Tumbler Ridge customers.

G-20-02 PNG

Postponed final argument filing date. Requested Intervenor comments on PNG revised revenue requirements application (regarding the Methanex Memorandum of Agreement) and proposed new timetable.

G-21-02 BC Hydro

Permitted decommissioning of the Boston Bar Diesel Generating Station, pursuant to Section 41 of the Act. BC Hydro is to file report upon project completion summarizing the net costs of the decommissioning.

G-22-02 PLP

Approved interim rates, effective April 1, 2002, subject to refund with interest following a written public hearing process on the 2002/03 Revenue Requirements Application.

G-23-02 PNG

Requested written comments on the issues raised by West Fraser et al. on the Revised 2002 Revenue Requirements Application.

G-24-02 BC Gas

Approved Rate Schedule 23 - Commercial Transportation Service Tariff Supplement No. A-4 with Fording Coal Limited for its greenhouse operations, effective November 1, 2001.

G-25-02 Centra Gas

Approved an increase in Pioneer customer rates effective May 1, 2002 as follows:

	Current Rate $/GJ	New Rate $/GJ	Percent Change Increase
SGS-1	11.88	12.37	4.12
SGS-2	10.57	11.01	4.16
LGS-1	8.20	8.54	4.15
LGS-2	7.72	8.04	4.15
LGS-3	7.25	7.55	4.14
CRR-Top	7.25	7.55	4.14
CRR-Bottom	5.94	6.19	4.21
ACR-1 (Minimum Use)			
Capital Regional District			
ACR-1 (200)	8.07	9.10	12.76
ACR-1 (600)	7.29	8.33	14.27
ACR-1 (2000)	7.29	8.33	14.27
ACR-1 (6000)	7.29	8.13	11.52
Other Communities			
ACR-1 (200)	8.46	9.49	12.17
ACR-1 (600)	7.68	8.71	13.41
ACR-1 (2000)	7.68	8.71	13.41
ACR-1 (6000)	7.68	8.13	5.86

G-26-02 PNG (N.E.)

Approved a lump sum refund of the excess margin received from Quintette Mines Limited to all Tumbler Ridge customer classifications based on the actual deliveries to each customer in 2001. A report on the results of the refund was filed on September 18, 2002.

G-27-02 BC Gas

Approved the recovery of $106,328 of actual deferral account costs incurred for the ABC-T project, over an amortization period of two years commencing in 2003.

G-28-02 BC Hydro

Denied the Office & Professional Employees' International Union, Local 378 application for a public hearing into proposals by BC Hydro to enter into joint venture/partnership arrangements to provide services, in that such arrangements would violate Sections 52 and 53 of the Act. Reasons for Decision were issued.

G-29-02 BC Gas

- Approved the disposition of the BC Gas Program Mercury and other customer care related assets to BC Gas Inc., effective December 31, 2002, in accordance with the Asset Transfer Agreement.
- Approved the two agreements with CustomerWorks, being a Client Services Agreement for the provision of customer care services, and a Shared Services Agreement for the provision of corporate support services, effective December 31, 2001.
- BC Gas is to provide a Report and Recommendation to the Commission for review prior to the renewal of contracts with CustomerWorks in 2007, or before committing to another service provider.
- Any significant improvement initiatives or scope changes pursuant to the Client Services Agreement are to be submitted to the Commission for review.

Reasons for Decision were issued.

G-30-02 CENTRAL COAST POWER CORPORATION

Amended Order No. G-40-86 with respect to Schedule F, which is appended to the Order, by striking out Section 2(c) and replacing it with "For present firm installed capacity in Central Coast's Ocean Falls generating facility, industrial customers are to be charged rates as negotiated by the parties, but not to exceed the rate authorized by BC Hydro's Rate Schedules 1821, 1200, 1201, 1210, or 1211 as amended from time to time, for similar service. In the event that additional generation, above the firm installed capacity of the plant is required, the parties may negotiate rates with consideration of the cost of installing additional generation."

Order No. G-40-86 was further amended by striking paragraph 2(a) and replacing it with "CCPC shall fully comply with the terms of its agreements with BC Hydro and Ocean Falls Corporation (except for Schedule F) attached as Appendices I and II respectively".

G-31-02 PNG AND PNG (N.E.)

Ordered the Oral public hearing to be reconvened and issued an amended Regulatory Timetable into the PNG-West revised 2002 Revenue Requirement Application and the Memorandum of Agreement with Methanex Corporation. Reasons for Decision were issued.

G-32-02 BC GAS

Approved Market-Based Commodity Rates for Rates Schedules 7, 10 and 14 and approved new Rate Schedule 14A for the 2002/03 gas contract year commencing November 1, 2002. The request for approval of Rate Schedule 10A was denied.

The Gas Management fee under Rate Schedule 14 will be maintained at $0.02/GJ to $0.08/GJ, and the Gas Management fee under Rate Schedule 14A will be $0.04/GJ to $0.08/GJ.

Within 30 days of the end of each month, BC Gas will file a report for Rate Schedules 14 and 14A summarizing the gas purchase and sale quantities and costs and revenue, for each price option for the month.

Reasons for Decision were issued.

G-33-02 BCUC

Public utilities are ordered to pay a fixed levy of $0.0077334691 per GJ equivalent to energy sold for the calendar year 2001, commencing April 1, 2002 to recover the Commission costs for the 2002/03 fiscal year. Also, pursuant to Levy Regulation 283/88 and Letter No. L-39-96, upstream natural gas processors and intra provincial oil pipelines are each ordered to pay $1,000 for the fiscal year commencing April 1, 2002.

G-34-02 CENTRA GAS

Approved an increase to Pioneer customer rates effective June 1, 2002 as follows:

	Current Rate ($/GJ)	New Rate ($/GJ)	Percent Change Increase
SGS-1	12.37	12.96	4.77%
SGS-2	11.01	11.63	5.63%
LGS-1	8.54	9.02	5.62%
LGS-2	8.04	8.50	5.72%
LGS-3	7.55	7.97	5.56%
CRR-Top	7.55	7.97	5.56%
CRR-Bottom	6.19	6.48	4.68%
ACR-1 (Min Use) Capital Regional District			
ACR-1 (200)	9.10	9.95	9.34%
ACR-1 (600)	8.33	9.18	10.20%
ACR-1 (2000)	8.33	8.76	5.16%
Other Communities			
ACR-1 (200)	9.49	10.34	8.96%
ACR-1 (600)	8.71	9.57	9.87%

G-35-02 PLP

Approved the creation of a holding (deferral) account to record extraordinary income and expenses from utility contracting activities, effective April 1, 2002, and accepted the balance of this account carried forward from prior years. PLP is to file an annual reconciliation of the deferral account when filing the Utility's Annual Report to the Commission. A detailed report on the effectiveness of the account covering the years 2003 to 2005 is to be filed by June 30, 2005, being the due date for PLP's 2005 Annual Report. PLP is to apply for approval of any changes to the accounting treatment of indirect cost allocation percentages.

G-36-02 PLP

Confirmed as permanent the interim rates for Service and Access Charges as set out in the Revised 2002/03 Revenue Requirements Application, effective April 1, 2002.

PLP is to provide comparative financial schedules as prescribed by the Commission, whenever it applies for a change in rates, accounting treatment, or when submitting its Annual Report. Those schedules must set out the cost components of the various rate categories, such as access, service, energy, as well as the contracting activities.

G-37-02 BC Gas

Extended the filing date required by Order No. G-123-01 for the 2003 Revenue Requirements Application to June 17, 2002.

G-38-02 PNG / PNG (N.E.)

Accepted PNG-West's recommendation that the current GCVA rider and Gas Supply Charges for PNG-West should remain and continue unchanged, except that the GCVA rider for Granisle propane customers is to be reduced to zero effective July 1, 2002.

Accepted PNG (N.E.)'s recommendation that the current GCVA riders and Gas Supply Charges for Tumbler Ridge and Fort St. John/Dawson Creek customers should remain and continue unchanged.

G-39-02 Toby Creek

Approved the Gas Tariff, General Terms and Conditions of Service and Propane Rates, effective June 1, 2002. (See also Order No. C-9-02)

G-40-02 BC Gas

Established a Workshop and Pre-hearing Conference to review the 2003 Revenue Requirements and Multi-Year Performance-Based Ratemaking Application.

G-41-02 BC Gas

Approved gas tariff changes to support the movement of its Lower Mainland natural gas customers from the BC Hydro billing system to the CustomerWorks billing system.

G-42-02 Aquila

Approved a 10-year loan in the amount of $50 million with an interest rate of 7.61 percent that will mature on June 15, 2011, pursuant to Section 5 of the Act.

G-43-02 PLP

Approved a revision in the KVA-ACCESS charges so that the equivalent rate under the non Time-of-Use rate schedules for Commercial Classes CXT1, CXT2, CXT3 and CXT4, would apply effective June 1, 2002.

G-44-02 PLP

Approved an extension of the PASs Energy Management Program with expenditures of $482,632 for the fiscal years ending March 31, 2003, 2004 and 2005. An annual report related to the PASS Energy Management Program activities is to be filed at the end of each year during the extension period. PLP is directed to apply for the reallocation of its PASS wages to the Company's SERVICE charges in its next revenue requirement or revenue allocation application.

G-45-02 Aquila

Approved the June 17, 2002 Letter Agreement with BC Hydro extending the May 16, 2000 Wholesale Transmission Service Agreement for the transmission of power from Aquila's South Slocan Generating Station to Aquila's Princeton Substation during off-peak hours for the period June 19 to July 31, 2002.

G-46-02 Aquila

Approved, pursuant to the Reasons for Decision issued as Appendix A to the Order, the final routing for the 230 kV Kootenay Development Project and the Brilliant Terminal Station Facilities Interconnection and Investment Agreement with Columbia Power Corporation and Columbia Basin Trust. Aquila is to file monthly progress reports and a final project report on the Kootenay 230 kV Project.

G-47-02 BC Hydro

Approved the continued deferral and amortization of foreign exchange gains and losses on the translation of foreign denominated long-term monetary items, using the straight-line pooled method, for the fiscal year beginning April 1, 2002 and future periods.

G-48-02 Office & Professional Employees' International Union, Local 378

Denied the OPEIU's June 7, 2002 Reconsideration Application of Commission Order No. G-28-02 and Reasons for Decision, as it had failed to substantiate its case on a prima facie basis.

G-49-02 BC Gas

Referred the Lease-In-Lease-Out arrangements with the City of Vernon to a written public hearing process.

G-50-02 Centra Gas BC

Approved a decrease in the Pioneer ACR-1 customer rates effective August 1, 2002 as follows:

	Current Rate ($/GJ)	Aug. 1/02 New Rate ($/GJ)	Percent Change (Decrease)
ACR-1 (Min Use)			
Capital Regional District			
ACR-1 (200)	9.95	9.70	(2.51)
ACR-1 (600)	9.18	8.92	(2.83)
Other Communities			
ACR-1 (200)	10.34	10.08	(2.51)
ACR-1 (600)	9.57	9.31	(2.72)

G-51-02 Aquila

Pursuant to Section 50 of the Act approved the issuance of Series J Debentures in the amount of $50 million at an interest rate of 6.75 percent issued at a discount to yield 6.762 percent and a term of seven years.

G-52-02 BC Gas

Issued a Regulatory Timetable for the review of the 2003 Revenue Requirements and Multi-Year Performance-Based Ratemaking Application.

G-53-02 BC Hydro

Approved the capitalization of ongoing negotiation and litigation costs with First Nations, the costs of settlements arising from those negotiations and the amortization of those costs over a ten-year period beginning in the 2001/02 fiscal year. The costs are with respect to alleged impacts as a result of the construction and operation of some of BC Hydro's facilities, namely, the Williston reservoir, the WAC Bennett dam, and the Bridge, Seton and Lajoie power stations.

G-54-02 BC Gas

Approved a Further Amended and Restated Bypass Transportation Agreement dated June 1, 2002 with Dunkley Lumber Limited for a ten-year term commencing November 1, 2002, which replaces the current bypass Transportation Agreement filed as Rate Schedule 25, Tariff Supplement No. E-2 that expires on November 1, 2002.

G-55-02 BC Gas

Approved a five-year extension to the expiry date of the Natural Gas for Vehicles Service Agreement with Beach Place Ventures Ltd. to commence August 15, 2002 identified as Tariff Supplement No. C-1.

G-56-02 PNG

Order issuing the Commission's Decision on the 2002 Revenue Requirements Application and the Methanex Application for a Load Retention Rate.

G-57-02 PNG (N.E.)

Order and Reasons for Decision relating to the 2002 Revenue Requirements Application approving a reduction in the revenue deficiency to approximately $213,000 for the Fort St. John/Dawson Creek Division and to approximately $61,000 for the Tumbler Ridge Division. PNG (N.E.) was directed to refund excess payments with interest back to customers.

G-58-02 WEI

Approved the transfer of exemption rights under Order No. G-58-91 from Westcoast Power Inc. to McMahon Power Holdings L.P. and varied the 1991 Order by deleting the operative clause on page 2 and replacing it as follows:

"1. WPI and CU Power and each of their respective successors in interest to the Project who:

(i) are affiliates as that term is defined by the Company Act, R.S.B.C. 1996, c.62; or
(ii) are corporations owned by WPI and CU Power,

are exempted from the application of provisions of Part 3 of the Act to the extent that those provisions would apply by reason of their ownership and operation of the Project.

2. Westcoast Energy Inc. is to notify the Commission when the transfer of ownership to McMahon Power Holdings L.P. is complete, and WPI and CU Power and their successors will notify the Commission within 90 days of any subsequent changes to the parties to which the exemption under this Order applies."

G-59-02 PNG (N.E.)

Accepted for filing, the February 1, 2002 Inter-Connect Agreement with Williams Energy (Canada) Inc., which replaced an earlier agreement that ended February 1, 2002, and has a term that extends to October 31, 2011. Payments under the Inter-Connect Agreement are to be recorded in an interest-bearing deferral account, and PNG (N.E.) is to address alternative toll treatments for these costs in an application for their recovery that is to be filed with the Commission prior to January 1, 2003.

G-60-02 CENTRA GAS

Approved a decrease to Pioneer ACR-1 customer rates effective September 1, 2002 as follows:

	Current Rate ($/GJ)	Sept. 1/02 New Rate ($/GJ)	Percent Change (Decrease)
ACR-1 (Min Use)			
Capital Regional District			
ACR-1 (200)	9.70	9.44	(2.68)
ACR-1 (600)	8.92	8.66	(2.91)
Other Communities			
ACR-1 (200)	10.08	9.83	(2.48)
ACR-1 (600)	9.31	9.05	(2.79)

G-61-02 STARGAS

Established a written public hearing process for the review of the Rate, Tariff and Ownership Changes Application.

G-62-02 PLP

Pursuant to Section 50 of the Act, approved the renewal of credit facilities dated August 15, 2002 with the Canadian Imperial Bank of Commerce in accordance with the July 3, 2001 Business Credit Agreement.

G-63-02 BC GAS

Referred the revenue requirement component of the 2003 Revenue Requirements and Multi-Year Performance-Based Ratemaking Application to an oral public hearing. (See Order No. G-90-02.)

G-64-02 CENTRA GAS

Approved rate increases effective October 1, 2002 as follows:

	Current Rate ($/GJ)	October 1/02 New Rate ($/GJ)	Percent Change Increase
ACR-1 (Min Use)			
Capital Regional District			
ACR-1 (200)	9.44	10.34	9.53
ACR-1 (600)	8.66	9.57	10.51
Other Communities			
ACR-1 (200)	9.83	10.73	9.16
ACR-1 (600)	9.05	9.71	7.29

G-65-02 CENTRA GAS

Approved the amended Customer Gas Appliance Finance Plan, to be operated by BC Gas Homeworks and funded by the Citizens Bank of Canada.

G-66-02 BC GAS

Approved the June 28, 2002 Lease-In/Lease-Out Application to enter into lease arrangements with the City of Vernon.

G-67-02 TOBY CREEK

Approved a Gas Cost Reconciliation Account with a zero initial balance to record propane supply costs and revenue commencing June 1, 2002.

A report on the Gas Cost Reconciliation Account balances is to be provided within 60 days following the end of the fiscal year.

G-68-02 WEI

Rescinded Order No. G-58-02 and varied Order No. G-58-91 by deleting the operative clause on Page 2 of the Order and replacing as follows:

"1. WPI and CU Power and each of their respective successors in interest to the Project (provided that at all times the ownership interests of such successors in interest are held directly or indirectly by Westcoast Energy Inc. or Canadian Utilities Limited), are exempted from the application of provisions of Part 3 of the Act to the extent that those provisions would apply by reason of their ownership and operation of the Project.

2. Westcoast Energy Inc. is to notify the Commission when the transfer of ownership to McMahon Power Holdings Limited Partnership is complete, and WPI and CU Power and their successors will notify the Commission within 90 days of any subsequent changes to the parties to which the exemption under this Order applies."

G-69-02 CENTRA GAS

Approved the September 3, 2002 Amendment to Industrial Gas Sales Agreement with the University of Victoria, effective August 25, 2002.

The Amendment to Industrial Gas Sales Agreement shall continue in effect until December 31, 2002, or until such time as new rates being considered by revenue requirements and rate design proceedings in the fall of 2002 become effective as approved by the Commission.

G-70-02 BC GAS

Approved Rate Schedule 22B - Large Industrial Rate Tariff Supplements No. G-14 and G-15 with Fording for its coal mine site operations at Fording River and Greenhills, effective August 1, 2002.

G-71-02 CENTRA GAS

Established a Workshop and Pre-hearing Conference in Nanaimo for the 1999 to 2001 Revenue Deficiencies and 2003 to 2005 Revenue Requirements Application, and the Rate Design and Proposed 2003 Rates Application.

G-72-02 TOBY CREEK

Accepted the Utility's request to withdraw its July 30, 2002 application to decrease its Gas Cost Recovery Charge for its Panorama, B.C. propane grid system.

Approved the September 30, 2002 application for a reduction in its Gas Recovery Charge from $8.57 per GJ to $7.61 per GJ effective November 1, 2002, pursuant to Sections 58, 60 and 61 of the Act.

Accepted for filing the August 31, 2001 Agreement between BCG Services Inc. and MP Energy Partnership for the supply of bulk propane to the Toby Creek propane grid system at Panorama for the period September 1, 2001 to August 31, 2003.

G-73-02 STARGAS

Ordered a Public Information Town Hall Meeting regarding Application for Approval of Rate, Tariff and Ownership Changes.

G-74-02 CENTRA GAS

Approved increases in Pioneer customer rates effective November 1, 2002 as follows:

	Current Rate ($/GJ)	November 1/02 New Rate ($/GJ)	Percent Change Increase
SGS-2	11.63	11.72	0.77
LGS-1	9.02	9.70	7.54
LGS-2	8.50	8.76	3.06
LGS-3	7.97	8.13	2.01
CRR-Top	7.97	8.13	2.01
ACR-1 (Min Use) Capital Regional District			
ACR-1 (200)	10.34	11.12	7.54
ACR-1 (600)	9.57	9.71	1.46
Other Communities			
ACR-1 (200)	10.73	11.51	7.27

G-75-02 BC HYDRO

Established a Written Public Hearing to review the CPCN Application for the Installation of New Circuit 2L33 from Horne Payne Substation (Burnaby) to Cathedral Square Substation (Vancouver).

G-76-02 CENTRA GAS

Issued a Regulatory Agenda and Timetable with key filing dates for the Negotiated Settlement proceedings relating to the 1999 to 2001 Revenue Deficiencies and 2003 to 2005 Revenue Requirements Application (Phase 1), and the Rate Design and Proposed 2003 Rates Application (Phase 2).

G-77-02 PNG AND PNG (N.E.)

Denied reconsideration or variance of Orders No. G-56-02 and Order No. G-57-02 and the Decisions that were issued concurrently with those Orders relating to the Utilities' 2002 Revenue Requirements.

G-78-02 EUROCAN PULP AND PAPER COMPANY

Denied reconsideration or variance of Order No. G-56-02 and the Commission's Decision relating to PNG's 2002 Revenue Requirements.

G-79-02 BC GAS

Approved the Gas Supply Mitigation Incentive Program 2002/03 for the gas contract year from November 1, 2002 through October 31, 2003.

G-80-02 STARGAS

Approved the following Rate, Tariff and Ownership Changes:

- An increase to the delivery charge component of rates by $2.00 GJ, effective December 1, 2002.
- A non-discretionary Administrative cost recover fee of 10 percent on the cost invoiced by contractors for all customer-initiated work, except the installation of a new customer service.
- Pursuant to Section 50 of the Act:

i) repayment of $115,000 of the existing advances from Silver Star Club Resorts Ltd. having no stated terms of repayment and bearing no interest,

ii) redemption of $235,000 of existing Class G non-voting preferred shares having a non-cumulative dividend of 8 percent, and

iii) replacement with $400,000 cumulative preferred shares.

The deferred dividend on preferred shares is to be calculated using the Commission's annual benchmark return on equity plus 75 basis points.

Approved, pursuant to Section 54 of the Act, the transfer of shares in the capital of Stargas and acquisition of a reviewable interest by Rundle Investments Ltd. (500 Class A shares) and C.M.I. Holdings (1998) Inc. (500 Class A shares).

Directed Stargas to coordinate a review of its unaccounted-for gas rate with BC Gas Services Ltd. and to adjust its charges at the next commodity gas cost review.

G-81-02 CENTRA GAS

Approved an increase to ACR-1 Pioneer customer rates effective December 1, 2002 as follows:

	Current Rate ($/GJ)	Dec 1/02 New Rate ($/GJ)	Percent Change Increase
ACR-1 (Min Use)			
Capital Regional District			
ACR-1 (200)	11.12	11.38	2.34
Other Communities			
ACR-1 (200)	11.51	11.72	1.82

G-82-02 CHDL

Ordered that a copy of this Order and the Executive Summary to the 2003 Revenue Requirements Application be provided to all current and prospective customers by November 22, 2002. A Timetable for Information Requests, Responses and the further review of the Application will be made by a future Order of the Commission. (See Order No. G-101-02.)

G-83-02 AQUILA

Established a 2002 Annual Review and a Public Information Town Hall Meeting for January 13, 2003. A Negotiated Settlement Process, to be held on January 14, 2003, was approved to determine rates for 2003. Effective January 1, 2003, an average interim rate increase of 5 percent was approved.

G-84-02 PNG

Approved the issuance of $15 million in secured debentures as described in the November 27, 2002 RoyNat Inc. Offer of Finance, pursuant to Sections 50 and 52 of the Act, and the creation of a deferral account to record the extent to which the floating interest rate on the secured debentures varies from that assumed for rate-making purposes in future revenue requirement applications.

G-85-02 BC Gas

Approved the Agreement with Labatt's Breweries of B.C. Ltd. as a Rate Schedule 14 Tariff Supplement, effective April 1 to October 31, 2003. Pricing under the Tariff Supplement will be equivalent to the provisions of the Rate Schedule 14 Firm Supply - Winter Fixed Price option.

G-86-02 Centra Gas

Referred the Phase 2 Rate Design Application to an oral public hearing process to establish permanent rates, effective January 1, 2003. The Utility was directed to file an application for Interim Rates effective January 1, 2003. A subsequent order establishing a hearing to review the Phase 1 Revenue Requirements Application will be issued should the tentative settlement agreement not be approved.

G-87-02 BC Hydro

Approved the November 22, 2002 Extension and Amending Agreement with the City of New Westminster, extending the December 31, 1999 Power Sale Agreement to June 30, 2003.

G-88-02 Sher-Dan Holdings ltd.

Approved the acquisition by Sher-Dan Holdings Ltd. (doing business as BCG Services) of a reviewable interest in the shares of Sun Rivers Services Corp, provided that the timely consent of the share purchase is received from her Majesty the Queen in Right of Canada and the Kamloops Indian Band.

G-89-02 Sun Rivers

Approved the registration of a transfer of the common shares of Sun Rivers Services Corp. to Sher-Dan Holdings Ltd. subject to the consent of the share purchase from Her Majesty the Queen in Right of Canada and the Kamloops Indian Band. Within 60 days of completion of the share purchase and in future Annual Reports, Services Corp. will provide information on rate base that is used to provide electricity and gas distribution services in a form that is consistent with the Commission's Standard Code of Accounts. The information will include capital expenditures, customer contributions and depreciation

G-90-02 BC Gas

Ordered that BC Gas' existing rate be made interim effective January 1, 2003, pending the Commission's Decision on the 2003 Revenue Requirements. Permanent rates will be effective January 1, 2003, subject to adjustment to recover any shortfall or to refund any surplus arising from any difference between the interim and the permanent rates as determined in the Commission's Decision.

G-91-02 PNG

Scheduled a Negotiated Settlement Process commencing February 10, 2003, to examine the 2003 Revenue Requirement Application. Accepted PNG's evidence in support of its requested interim rate increases, except for the revenue requirement resulting from the requested increase in the common equity component.

Approved an interim rate increase in the delivery charge for all classes of customers, except Methanex Corporation.

Approved interim increases in Gas Supply Charges and interim changes to GCVA riders that would amortize the projected December 31, 2002 GCVA balances for core market sales and company use gas over 2003, excluding the 2000 unaccounted for gas Volume Deferral Credit, pursuant to Sections 89 and 91 of the Act.

G-92-02 PNG (N.E.)

Order establishing a written public hearing to review the 2003 Revenue Requirements Application. Evidence in support of the requested interim rate increases, except for the revenue requirement resulting from the requested increase in the common equity component for the Tumbler Ridge Division, was accepted.

Approved an interim rate increase in the delivery charge for all classes of customers, excluding the revenue requirement resulting from the common equity component for the Tumbler Ridge Division, pursuant to Sections 89 and 91 of the Act.

Approved interim increases in Gas Supply Charges and an interim increase to $0.30/GJ for the Tumbler Ridge GCVA rider. Directed PNG (N.E.) to make an interim change to GCVA rider for Fort St. John and Dawson Creek that would amortize the projected December 21, 2003 GCVA balance for Fort St. John/Dawson Creek over 2003.

G-93-02 PLP

Approved a 5 percent interim increase to the energy component of rates for all customers resulting from the pass-through of increased power purchase costs from Aquila, effective January 1, 2003.

G-94-02 CENTRA WHISTLER

Approved an interim rate increase of 5.96 percent, effective January 1, 2003, subject to refund, pending the Commission's Decision on the 2003 Revenue Requirements Application.

G-95-02 AQUILA

Approved amendments to the Electric Tariff Terms and Conditions allowing the Utility to issue final bills based on estimates or allowing the customer the option to read the meter and supply the information for billing purposes.

G-96-02 CENTRA GAS

Rescinded the Regulatory Timetable issued in Order No. G-86-02 and replaced it with the Regulatory Timetable attached to this order, with the respect to the 2002 Rate Design and Proposed 2003 Rates Application.

G-97-02 CENTRA GAS

Approved the rate class segments and interim rates proposed by Centra, effective January 1, 2003, until the Commission has determined permanent rates for all customers (except the ACR-2 class as stipulated in the Special Direction attached to Order in Council 1510, 1995). The interim rate increases are subject to refund pending the outcome of the public hearing into the 2003 Revenue Requirements Application.

Approved the closure of the New Customer rate class tariffs established by Sections 2.2(b) and 2 7 of the Special Direction, and in particular the Small General Service - SGS-11, SGS-12, Large General Service - LGS-11, LGS-12 and LGS 13 classes and the Rate Rider C pertaining to the New Customer Rate Balancing Account cost of gas recovery rider.

G-98-02 SQUAMISH GAS

Approved Squamish Gas' proposal that the competitive fuel rate setting mechanism continue beyond December 31, 2001 and that the stated discounts in Schedule A of the Squamish RSA are no longer applicable, effective January 1, 2003. Approved increases in rates effective January 1, 2003 ranging from 3.19 to 14.25 percent.

G-99-02 BC HYDRO

Approved amendments to Rate Schedule 1852: Transmission Service - Modified Demand and Rate Schedule 1880: Transmission Service - Emergency, Maintenance and Special Supply, effective December 19, 2002.

G-100-02 AQUILA

Established a written public hearing for the review of the Aquila CPCN application for the South Okanagan Supply Reinforcement Project and BC Hydro's application to amend the General Wheeling Agreement and Power Purchase Agreement with Aquila.

G-101-02 CHDL

Established a Negotiated Settlement Process to review the 2003 Revenue Requirements and set the current rates of CHDL as interim, effective January 1, 2003.

G-102-02 BC GAS

Approved an allowed ROE for BC Gas for 2003 of 9.42 percent to be incorporated with any other adjustments to BC Gas' permanent rates arising from the Commission's Decision regarding the BC Gas 2003 Revenue Requirement, effective January 1, 2003, pursuant to Sections 58, 60, 61 and 89 of the Act.

G-1-03 NELSON

Approved and accepted for filing Electrical Utility Amendment By-Law No. 2959, 2002 incorporating a 1.50 percent rate increase, effective January 1, 2003.

G-2-03 CENTRA GAS BC

Approved the Negotiated Settlement as issued on December 24, 2002, pertaining to the 1999 to 2001 actual revenue deficiencies and 2003 to 2005 forecast revenue requirements.

G-3-03 BC GAS

Approved revisions to Rate Schedules 14 and 14A - Term and Spot Gas Sales to replace the Winter Fixed Price Option with a Term Fixed Price Option for the 2002/03 gas contract year.

G-4-03 CHDL

Approved the Negotiated Settlement and an average permanent rate increase in the Steam Tariff Schedule of Charges of 4.362 percent, effective January 1, 2003, to recover a 2003 revenue deficiency of $243,929. (See Order No. G-8-03.)

G-5-03 CENTRA WHISTLER

Established a Negotiated Settlement Process for the review of the 2003 Revenue Requirements Application.

G-6-03 BC GAS

- Approved the amended and restated Rate Schedule 27 Interruptible Transportation Agreement with International Forest Products Ltd. as Tariff Supplement No. E-10, effective November 1, 2002 to October 31, 2007.

- Approved the amended and restated Interruptible Liquefied Natural Gas Agreement with International Forest Products Ltd. as Tariff Supplement No. I-5, effective November 1, 2002 to October 31, 2007.

G-7-03 BC GAS

Order issuing the Commission's Decision and confirming a permanent increase in revenue requirements for 2003 of approximately $12.2 million, pursuant to Sections 58 and 60 of the Act.

G-8-03 CHDL

Approved an amendment of $59,900 to the pension expense forecast contained in the 2003 Negotiated Settlement, subject to review on complaint within 60 days of this Order. The amendment increased CHDL's 2003 revenue deficiency from $243,929 to $303,829 resulting in an average permanent rate increase in the Steam Tariff Schedule of Charges of 5.432 percent, effective January 1, 2003. (See Order No. G-4-03.)

G-9-03 BC GAS

Approved the cancellation of Tariff Supplement No. I-1 with PG&E Energy Trading, Canada Corporation, effective January 1, 2003.

Approved and accepted for filing Tariff Supplement No. I-6 with Northwest Natural Gas Company for approximately 42,500 Mcfd of SCP capacity, effective November 1, 2004.

G-10-03 AQUILA

Approved the Negotiated Settlement as issued on January 31, 2003 and a general rate increase of 4.3 percent for all customer classes, effective January 1, 2003 for the 2002 Annual Review and 2003 Revenue Requirements Application.

G-11-03 CENTRA WHISTLER

Amended the Negotiated Settlement Process commencement date as set out in Commission Order No. G-5-03 to March 25, 2003 in Whistler, B.C. with respect to approval of Centra Whistler's 2003 Revenue Requirements.

G-12-03 PLP

Pursuant to Sections 58, 61, 89 and 91 of the Act, the energy rates regarding the pass-through of decreased power purchase costs and 2003/04 Revenue Requirements were approved on a permanent basis, effective January 1, 2003. The increases in service and access charges proposed on an interim basis were approved, effective April 1, 2003, subject to refund with interest following a written public hearing process.

G-13-03 PNG

Approved a new credit facility of $25,000,000 with the National Bank of Canada, pursuant to Sections 50 and 52 of the Act. PNG is directed to inform the Commission of any significant departure in the terms and conditions of the indebtedness and will record all net benefits derived from the new credit facility in the existing interest expense deferral account.

G-14-03 PNG

Approved the Negotiated Settlement for the 2003 Revenue Requirements as issued on February 21, 2003, pursuant to Sections 58, 89 and 91 of the Act. The difference between the interim increase and the approved revenue requirement are to be refunded with interest at the average prime rate of PNG's principal bank, as directed by Order No. G-91-02.

PNG is to file an amended Summary of Rates and Bill Comparison schedule, report the average refund by customer class resulting from the 2003 permanent rates and advise whether it should occur as a customer credit or refund payment.

G-15-03 PNG (N.E.)

Approved the provision of a guarantee to the National Bank of Canada for amounts owed by Pacific Northern Gas Ltd. and to provide security for the guarantee, pursuant to Sections 50 and 52 of the Act.

G-16-03 Squamish Gas

Approved increases in rates to LGS, CRR and ACR-1 customers, ranging from 9.16 to 14.12 percent, effective April 1, 2003.

G-17-03 Toby Creek

Approved an increase in propane rates to $10.87/GJ for all customers effective April 1, 2003.

G-18-03 BC Hydro

Approved an exemption from the provisions of BC Hydro's Wholesale Transmission Services Tariff (Tariff Supplement No. 30 and Rate Schedules 3000 to 3010 inclusive), for power flowing on its system pursuant to the Teck Cominco/BC Hydro Line 71 Agreement and the Line 71 Amending Agreement.

G-19-03 BC Gas

Approved changes to the Gas Cost Recovery Charges, effective April 1, 2003, as follows:

- An increase in the commodity charge for the Lower Mainland, Inland and Columbia customers of $1.699/GJ to $8.30/GJ
- An increase in the commodity charge for the Fort Nelson customers of $1.67/GJ
- No changes to propane rates were requested for the Revelstoke prograne grid system.

G-20-03 PNG & PNG (N.E.)

Approved changes to the Gas Supply Charges, Company Use Gas Charges, and Gas Cost Variance Account riders as filed on March 19, 2003, effective to consumption from April 1, 2003.

G-21-03 VIEC / VIGP

Order establishing Workshops to be held in Nanaimo to address the Vancouver Island Peak and Annual Demand and Supply, the condition of HVDC Cables and Reliability of Supply, the Feasibility of New Transmission Lines and Other Supply Alternatives, and the Vancouver Island Generation Project and GSX Project. A Pre-hearing Conference was also scheduled to follow the Workshops.

G-22-03 PNG (N.E.)

Order issuing Reasons for Decision on PNG (N.E.)'s 2003 Revenue Requirements Application.

Certificates of Public Convenience and Necessity

C-1-02 BC GAS

Approved a one-year extension to CPCN No. C-22-80 extending the expiry date of the Operating Agreement with the District of 100 Mile House and the continued payments of franchise fees to the District to June 30, 2002, or 60 days after the Commission's approval of a new operating agreement between the utility and the District.

C-2-02 BC GAS

Approved the November 1, 2001 Franchise Amendment Agreement with the City of Kelowna, pursuant to Section 45(7) of the Act.

C-3-02 BC GAS

Approved Transmission Pipeline Integrity Plan ("TPIP") expenditures for 2001 and 2002, except for expenditures related to the Noons Creek to Eagle Mountain segment, for a total estimated cost of $7.469 million. An Allowance for Funds Used During Construction may be recorded on those cost items approved as capital expenditures until such time as the capital costs are added to utility rate base. BC Gas will address which project costs are capital expenditures, which should be expensed annually, and whether some costs should be deferred and amortized over an appropriate period in its next revenue requirements application.

Within 60 days of the end of each calendar year, BC Gas will file a report on TPIP activities during the year.

C-4-02 UNC

Approved the renovations and upgrades to the Trail District Facilities at an estimated cost of $4.63 million. A final report and summary of actual costs is to be filed upon completion of the project.

C-5-02 CENTRA GAS BC

Approved the lowering of the natural gas transmission line where the pipeline crosses the Qualicum River at an estimated cost of $1,000,000. A final report, including a comparison of actual and estimated costs, is to be filed upon completion of the project.

C-6-02 BC GAS

Approved the Armstrong Compressor Station project for a total estimated cost of $4.246 million, with a range of accuracy of plus or minus 10 percent. BC Gas is to advise the Commission of the date that the compressor becomes available for local manually-operated service, and file quarterly progress reports. A comprehensive final report is to be filed upon completion of the project.

C-7-02 UNC

Approved the upgrade of the Trail area feeder network at an estimated cost of $1,500,600. The project consists of:

Constructing approximately 7 km of feeder extensions from the Stoney Creek substation and the Glenmerry substation, and related switching facilities;

- Upgrading the existing 50-year old 2.4 kV delta configured distribution systems, which serve the areas of Annable, Tadanac and a portion of the downtown core of Trail, to a grounded 12.47 kV system; and
- Removing the existing North Warfield 63/2.4 kV substation.

A final report and summary of actual costs is to be filed upon completion of the project.

C-8-02 BC GAS

Approved a further one-year extension to CPCN No. C-20-80 and the continuation of the payment of the 3 percent franchise fee to the District of Chetwynd to June 30, 2003.

C-9-02 TOBY CREEK

Approved the construction and operation of a propane gas distribution grid system at Panorama Mountain Village. (See Order No. G-39-02.)

C-10-02 UNC (AQUILA)

Approved the expenditure of $500,000 to secure a right-of-way for a section of the Transmission Line No. 44 within the boundaries of the Osoyoos Indian Reserve No. 1 between Oliver and Osoyoos.

C-11-02 AQUILA

Approved Phase 2 of the Joe Rich Double Circuit Project estimated to cost $1,231,500, pursuant to Section 45 of the Act. Aquila is to file annual progress reports and a final report on completion of Phase 2.

C-12-02 BC GAS

Approved a one-year extension to October 31, 2003 of the Gas Franchise Agreement with the City of Prince George.

C-13-02 BC GAS

Approved a one-year extension of the Operating Agreement and continuation of the payment of franchise fees with the Corporation of the District of 100 Mile House to June 30, 2003 (or 60 days after approval of a new Operating Agreement, whichever is earlier) pursuant to Section 45(7) of the Act.

C-14-02 BC HYDRO

Approved the installation of a new 230 kV Circuit 2L33 at an estimated cost of $43.8 million, pursuant to Sections 45 and 46 of the Act. BC Hydro is to file monthly progress reports and a final report after circuit energization.

C-15-02 CENTRA GAS

Approved the Sooke Distribution Extension Project, subject to the utility filing an agreement with BC Transportation Financing Authority and Capital Regional District Parks or other documentation that provides the right to use the Galloping Goose right-of-way for the Pipeline over the long term. Centra Gas is to file progress reports within 30 days of the end of each month and a final report, with justification of any cost overruns relative to the estimate of $4,261,811. The Utility will file annual reports that compare actual customer and load additions for the extension. The request to record Allowance for Funds Used During Construction at a rate equivalent to its weighted average cost of capital was approved.

C-1-03 AQUILA

Approved the West Trail Voltage Conversion Project at an estimated cost of $1,500,000 pursuant to Section 45 of the Act. Aquila is to file a final report and summary of actual costs upon completion of the Project.

C-2-03 AQUILA

Issued a CPCN to proceed with the Lambert Terminal Upgrade Project estimated to cost $4,257,500. Monthly progress reports are to be filed followed by a final report on completion of the project.

Other Orders

ENERGY SUPPLY CONTRACTS

E-1-02	**CENTRA GAS BC**	Seasonal Natural Gas Supply Contracts for the 2001/02 Gas Contract Year with IGI Resources Inc.
E-2-02	**UNC**	Power Purchase Agreements with Aquila Power Corporation
E-3-02	**BC GAS**	Natural Gas Storage Agreement with Puget Sound Energy Inc. - Jackson Prairie Storage Facility
E-4-02	**BC GAS**	Natural Gas Storage Agreement with Unocal Canada Limited - Aitken Creek Storage Facility
E-5-02	**BC GAS**	Natural Gas Storage Agreement with Northwest Natural Gas Company
E-6-02	**BC GAS**	Natural Gas Storage Agreements with Avista Corp. and Northwest Natural Gas Company
E-7-02	**CENTRA GAS BC**	Natural Gas Storage Agreement with BC Gas Utility Ltd.
E-8-02	**PNG-WEST**	2002/03 Seasonal and Peaking Gas Supply Contract with Duke Energy Marketing Limited Partnership
E-9-02	**CENTRA GAS**	Natural Gas Supply Agreements for the 2002/03 Gas Contract Year with Petro-Canada Oil and Gas, Coral Energy Canada Inc., Imperial Oil Resources, EnCana Oil & Gas Partnership and Husky Energy Marketing
E-10-02	**CENTRA GAS**	Pricing Amendment to a Baseload Gas Purchase Agreement with Talisman Energy Canada
E-11-02	**CENTRA GAS**	Seasonal Natural Gas Supply Agreement for the 2002/03 Gas Contract Year with BC Gas Utility Ltd.
E-12-02	**BC GAS**	Natural Gas Supply Contracts and Amendments for the 2002/03 Gas Contract Year
E-1-03	**BC GAS**	Fort Nelson - Natural Gas Supply Contract Revisions for the 2003/03 Gas Contract Year and Aitken Creek Storage

PARTICIPANT ASSISTANCE/COST AWARDS

F-1-02	**UNC**	2002 Revenue Requirements and the 2001 Annual Review - $10,369.42
F-2-02	**BC GAS**	Disposition of Property and Approval of Customer Care Agreements - $8,620.00
F-3-02	**PNG-WEST**	2002 Revenue Requirements - $25,489.27
F-4-02	**PNG (N.E.)**	2002 Revenue Requirements - $6,632.93
F-1-03	**AQUILA**	2002 Annual Review and 2003 Revenue Requirements - $781.51
F-2-03	**BC GAS**	2003 Revenue Requirements - $68,860.85

PETROLEUM

P-1-02	**TME**	2002 Jet Fuel Pipeline Tolls
P-2-02	**PLATEAU**	2002 to 2007 Tolls
P-3-02	**PLATEAU**	Sunset Prairie Crude Oil Pipeline Tolls effective July 1, 2002
P-4-02	**TME**	Approval of 2003 Tolls on the Jet Fuel Pipeline
P-1-03	**PLATEAU**	2003 Tolls for the Northeast B.C. and Blueberry Crude Oil Pipelines

Commission Letters

L-1-02 BC HYDRO

Requested BC Hydro to review and provide the Commission with its comments regarding the complaint filed by the Office & Professional Employees' International Union, Local 378 regarding the proposed consolidation, amalgamation or merger of the utility.

L-2-02 BC HYDRO

Letter acknowledging the December 31, 2001 report on the General Service Time-of-Use Pilot Program and offering to work with the utility to develop a permanent program, which can overcome the initial shortcomings of the Pilot Program.

L-3-02 UNC

Letter to Mr. Karow enclosing the Commission's Reconsideration Criteria and requesting that he refile his Application for Reconsideration of the Ootischenia Water and Land Stewardship Committee Action Group Complaint on the Routing of the 230 kV Transmission Line through Ootischenia, in the appropriate format.

L-4-02 BC GAS

Requested BC Gas to comment on the Commission's determination that the requested process suggested by the Utility to approve a standard form agreement between BC Gas and municipalities in the Inland and Columbia service territories is inconsistent with the Commission's authority under Section 32 of the Act.

L-5-02 APOLLO FOREST PRODUCTS LTD.

Letter acknowledging Apollo's December 21, 2001 and January 17, 2002 letters indicating that the company anticipates lower initial load growth and does not intend to build its substation until the phase 2 expansion is confirmed.

L-6-02 PNG

Letter amending the 2002 Revenue Requirements Regulatory Timetable filing dates for Intervenor Evidence, Information Requests on Intervenor Evidence, and Intervenor Information Responses.

L-7-02 BC GAS

Letter accepting the 2000 Main Extension Review Report (Amended) as filed and relieving the utility of the requirement to file future reports. Customer complaints or inquiries regarding the system extension test will be reviewed on an individual basis.

L-8-02 SUN PEAKS

Letter to Mr. Nielsen, Dansk Alpine Developments Ltd., denying his complaint regarding the overhead charges for repairing the natural gas line.

L-9-02 PNG / PNG (N.E.)

Advised the utilities that they may cease filing the monthly complaint reports as required under Letter No. L-27-01.

L-10-02 CENTRA GAS

Letter advising that the 2002 forecast capitalization of operating and maintenance expenditures of $4,912,300 was acceptable.

L-11-02 UNC

Letter permitting additional responses by UNC and Columbia Power Corporation/CBT Energy Inc. regarding Mr. Wait's reply argument of March 7, 2002. A final reply by Mr. Wait to the additional responses by UNC and Columbia Power Corporation/CBT Energy Inc. was also approved.

L-12-02 BC GAS

Approved for 2002 the continuation of the practice of deferring Demand-Side Management customer incentives to a maximum of $1,585,000 and the amortization of the deferred balance over the following three years.

L-13-02 BC GAS

Accepted BC Gas' recommendation that the Gas Cost Recovery Charges and Gas cost Reconciliation Account riders not change as of April 1, 2002.

L-14-02 CENTRA GAS BC

Approved Centra Gas' request to retain the existing Rate Rider C of $1.705/GJ for the second quarter of 2002.

L-15-02 PNG (N.E.)

Approved an extension to the 2002 Revenue Requirements Regulatory Timetable for the filing of Intervenor submissions and PNG (N.E.)'s reply argument.

L-16-02 PNG (N.E.)

Issued a revised Regulatory Timetable and amended filing dates for Intervenor arguments and the Utility's reply argument relating to the 2002 Revenue Requirements Application.

L-17-02 BC GAS

Extended the filing date for the 2001 Annual Reports for the Lower Mainland, Inland, Columbia and Fort Nelson service areas to no later than June 30, 2002.

L-18-02 UNC

Letter to complainant denying a request for reconsideration of the 1996 Brilliant Power Purchase Agreement.

L-19-02 CENTRA GAS BC

Accepted Centra Gas' proposal that the Cost of Service Allocation Study and three-year Revenue Requirements Application be filed by June 30, 2002 and the Rate Design Application be filed by July 30, 2002. Also accepted Centra Gas' proposal for a joint review.

A workshop to discuss further process will be set following those filings.

L-20-02 UNC

Approved in principle the replacement of $50 million in financing (maturing May 18, 2004) with $50 million in financing maturing on June 15, 2011. (See Order No. G-42-02 granting final approval.)

L-21-02 UNC

Letter acknowledging proposed name change of UtiliCorp Networks Canada (British Columbia) Ltd. to Aquila Networks Canada (British Columbia) Ltd., effective May 31, 2002.

L-22-02 BC GAS

Accepted utility recommendation that the Gas Cost Recovery Charges and Gas Cost Reconciliation Account riders remain unchanged as of July 1, 2002.

L-23-02 BC HYDRO

Letter establishing a written submission process to address whether the threshold for reconsideration has been met for each issued disclosed in the OPEIU June 7, 2002 Application for Reconsideration of Commission Order No. G-28-02 and Reasons for Decision.

L-24-02 CENTRA GAS BC

Accepted utility recommendation that the New Customer Rate Balancing Account Rate Rider C remain unchanged at $1.705/GJ as of July 1, 2002.

L-25-02 UNC / AQUILA

Approved the August 31, 2002 Subcontractor Agreement with UtiliCorp British Columbia Ltd. The Commission anticipates that the net revenues to Aquila from the Agreement will be treated as "Other Income" and shared between the utility and its ratepayers under the current incentive agreement until it expires on December 31, 2002.

L-26-02 BC HYDRO

Approved and accepted for filing the diesel generation costs covering the period July 1, 2002 to June 30, 2003 that will affect the following tariff supplements:

- Electric Tariff Supplement No. 7 - Interruptible Electricity Supply Agreement with Central Coast Power Corporation at an energy charge of 18.71 cents per kWh; and

- Electric Tariff Supplement No. 8 - Interruptible Electricity Supply Agreement with Queen Charlotte Power Corporation at an energy charge of 18.71 cents per kWh.

L-27-02 AQUILA

Letter to complainant regarding the application of Electric Tariff Section 8.1 - Interruptible and Deficit in Service with respect to damages incurred in 2002 due to power outages and surges.

L-28-02 AQUILA

Approved in principle the issuance of $50 million in a new series of debentures identified as Series J at an interest rate not to exceed 7.2 percent. (See Order No. G-51-02.)

L-29-02 BC GAS

Approved the continuation of the Revelstoke supply of liquid propane from MP Energy and the continuation of a winter-fixed /summer-variable with price cap pricing structure that conformed to the strategy approved by Order No. E-8-01.

Also approved the utility recommendation that Revelstoke propane rates should remain unchanged as at July 1, 2002.

L-30-02 BC GAS

Accepted the 2002/03 Gas Contracting Plan on the understanding that all individual gas supply contracts and amendments will continue to be filed in a timely fashion pursuant to Section 71 of the Act.

Commission comments noted in Appendix A and the 2002/03 Gas Contracting Plan, except for the material on load forecasting contained in the Executive Summary, will be held on a "confidential" basis on the understanding that it contains commercially sensitive information related to energy supply contracts.

L-31-02 PNG / PNG (N.E.)

Letter regarding the PNG/PNG (N.E.) applications reconsideration and variance of the Commission's July 31, 2002 Decisions with respect to the utilities' 2002 Revenue Requirements Applications.

- Invited PNG/PNG (N.E.) to provide additional information in support of their requests for reconsideration and variance.
- Invited Intervenors to provide comments on whether there should be a reconsideration.
- Directed PNG/PNG (N.E.) to respond to Intervenor comments.

L-32-02 PNG

Letter to Intervenors requesting comments on Eurocan's application for reconsideration and variance of the Commission's July 31, 2002 Decision on PNG's 2002 Revenue Requirements.

L-33-02 PNG

Confirmed PNG's proposal to record the Copper River slide preliminary repair costs in the Extraordinary Plant Losses and Line Break Costs deferral accounts, pending Commission approval of the final costs and amortization period.

L-34-02 AQUILA

Letter to Mr. Karow of the Coalition to Reduce Electropollution denying his application for reconsideration of the Commission's Reasons for Decision attached to Order No. G-46-02 on the Final Routing, Cost Estimate and Agreements for the Kootenay 230 kV System Development Project. The Commission determined that Mr. Karow had not provided evidence on a prima facie basis to demonstrate an error of material substance regarding electric and magnetic field impacts and that his application and arguments did not meet the threshold criteria for reconsideration.

L-35-02 CENTRA GAS

Letter agreeing in principle to the utility's proposal for concurrent review of this Revenue Requirements and Rate Design Applications provided the Rate Design Application is filed prior to September 27, 2002.

L-36-02 SQUAMISH GAS

Letter to the Ministry of Energy and Mines, Resource Development Division, stating that the 2000 and 2001 actual results of the Squamish Rate Stabilization Agreement were in accordance with Section 3 of the Squamish RSA, the April 1997 Settlement Agreement and the return on common equity allowed for by Order No. G-85-98.

L-37-02 BC GAS

Approved the Third Quarter 2002 Reports on Gas Cost Flow-Through and Gas Cost Reconciliation Accounts for the Lower Mainland, Inland, Columbia, Revelstoke and Fort Nelson service areas recommending that the gas cost recovery charges and gas cost reconciliation account riders not change effective October 1, 2002.

Letter also requested comments regarding the quarterly review process based on utility experience over 2001 and 2002 and the utility's assessment of the effectiveness of the quarterly reporting Guidelines (see Letter No. L-5-01) to be filed with the Fourth Quarter 2002 reports.

L-38-02 PNG

Accepted the Gas Contracting Plan and Gas Supply Price Management Plan for the 2002/2003 period subject to Commission considerations.

L-39-02 BC Gas

Information request regarding the accuracy of Lower Mainland bill estimates.

L-40-02 PNG / PNG (N.E.)

Accepted recommendation that the current Gas Supply Charges and Gas Cost Variance Account riders for PNG-West, PNG (N.E.) and Granisle continue at their present levels effective October 1, 2002. The Commission recognized that PNG has no gas in storage for 2002/03, is limited in its hedging capability, and that current expectations indicate gas costs in the next 12 months are likely to be significantly higher than expected revenue. PNG was directed to monitor its forecast gas costs on an ongoing basis and to apply for changes to gas commodity rates prior to January 2003 if necessary.

Letter also requested comments regarding the quarterly review process based on utility experience over 2001 and 2002 and the utility's assessment of the effectiveness of the quarterly reporting Guidelines (see Letter No. L-5-01) to be filed with the Fourth Quarter 2002 reports.

L-41-02 Centra Gas

Approved the continuation of the existing Rate Rider C of $1.705/GJ for the third quarter, effective October 1, 2002.

Letter also requested comments regarding the quarterly review process based on utility experience over 2001 and 2002 and the utility's assessment of the effectiveness of the quarterly reporting Guidelines (see Letter No. L-5-01) to be filed with the Fourth Quarter 2002 reports.

L-42-02 BC Gas

Letter to Intervenors in the 2003 Revenue Requirements review process listing the issues that will be excluded from the public hearing process as they are based on other current or pending processes, on Orders and Decisions already made, or not directly relevant to the one-year revenue requirement application.

Letter also established two working groups to review and report on the following:

- Tariff wording changes that mainly affect Transportation customers.
- Load Forecasts for Residential, Commercial and Large Commercial Customers.

L-43-02 Aquila

Letter approving the inclusion of a $450,000 dam rehabilitation phase for the Upper Bonnington Unit 5 Upgrade and Life Extension Project that was approved by CPCN No. C-2-01.

Aquila was requested to prepare a summary list of all projects completed and the status of final reports for those projects as well as a summary list of present and future projects and their estimated costs, and their expected timing over the next ten years.

L-44-02 BC Gas

Approved the withdrawal of the Rate Schedule 7 - Propane Service to Revelstoke Customers Application.

L-45-02 PNG

Accepted revisions to the 2002/03 Gas Supply Price Management Plan effective for the gas contract year commencing November 1, 2002. The revisions provide PNG with discretion regarding the timing of when risk management actions are to be implemented as well as the risk management instruments to be used. PNG is required to inform the Commission within 30 days of actions it has taken with respect to the GSPMP on an ongoing basis.

L-46-02 PNG / Aquila / BC Gas / Centra Gas

Letter establishing 9.42 percent as the appropriate return on common equity for a low-risk benchmark utility for the year 2003.

L-47-02 PORT ALICE

Approved the extension of the liquid propane supply contract with AutoGas Propane Ltd. for the period April 1, 2003 through March 31, 2004.

L-48-02 BC GAS

Letter discussing the following proposed set of transactions designed to preserve the value of the Southern Crossing Pipeline capacity contracted to PG&E Energy Trading, Canada Corporation:

- PG&E and BC Gas will terminate the Transportation Agreement and the Peaking Gas Purchase Agreement effective January 1, 2003. PG&E has also agreed to assign an equivalent amount of upstream TransCanada PipeLines Ltd. Nova/ANG capacity to BC Gas effective January 1, 2003. BC Gas has agreed to make certain payments to PG&E over the period through October 2019 and PG&E has an option to convert the payment stream to a net present value payment.

- BC Gas will enter into a firm service contract with Northwest Natural Gas Company for 46,500 Mcfd of SCP capacity for the period November 2004 through October 2020. Effective November 1, 2004, BC Gas will also assign an equivalent amount of TCPL service to NWN.

L-49-02 BC GAS

Pursuant to Policy Action No. 19 of the Province's Energy Policy, requested BC Gas to develop a report that would provide the following information relating to the unbundling of residential and commercial gas sales, Agency, Billing and Collection for Transportation Service.

- A schedule and cost estimate to achieve an implementation date of November 2004 for ABC-T service that includes meetings with all interested parties. The Commission expects this would substantially be an update of BC Gas' August 10, 2001 report.

- A discussion on whether the business model can be modified to accommodate marketers' concerns (such as supply balancing requirement and the proposed one year contract with consumers) and a consultative process for addressing these matters.

- Alternative rate offerings that BC Gas proposes to provide in conjunction with ABC-T service.

- An update on the discussion with municipalities related to restructuring the methodology for calculating franchise fees.

L-50-02 BC GAS

Approved the Fourth Quarter 2002 Reports on Gas Cost Flow-Through and Gas Cost Reconciliation Accounts for the Lower Mainland, Inland, Columbia, Revelstoke and Fort nelson service areas recommending that the gas cost recovery charges and gas cost reconciliation account riders not change effective January 1, 2003.

L-51-02 BC HYDRO

Exempted from the requirements to apply for a CPCN, the minor relocation of a 1.2 kilometer section of Circuit 1L364 over Cache Creek, west of Fort St. John.

L-52-02 BC HYDRO

Letter inviting BC Hydro to comment on the issues raised in Mr. Wheatley et al. application for net metering for residential customers, pursuant to Policy Action No. 20.

L-1-03 OFFICE & PROFESSIONAL EMPLOYEES' INTERNATIONAL UNION, LOCAL 378

Letter requesting BC Hydro to respond by January 31, 2003 to the OPEIU's request for a public hearing and for the Commission to exercise its jurisdiction to examine the divestment of a significant portion of BC Hydro's enterprise to a privately held company.

L-2-03 CENTRA GAS

Letter amending the Phase 2 Rate Design Regulatory Timetable to include the review of the following Amending Agreements and the impact on the proposed 2003 rates and cost of service.

- Amending Agreement to the BC Hydro Transportation Service Agreement dated October 17, 2002.

- Amending Agreement to the BC Hydro Capacity Assignment Agreement dated October 17, 2002.

- Amending Agreement to the BC Hydro Peaking Agreement datd October 17, 2002.

L-3-03 BC Hydro

Letter requesting a report by June 30, 2003 assessing the merits of a net metering policy as proposed by Michael Wheatley et al., and as noted in Policy Action No. 20 of the Province's Energy Policy.

L-4-03 Alberni Aluminium Corporation

Response to Alberni Aluminium complaint confirming BC Hydro's interpretation of Rate Schedule 1821-Transmission Service and the terms and conditions of service as it applies to Alberni Aluminium's proposed aluminum smelter in the Alberni Valley.

L-5-03 BC Gas

Response to Woodland Forest Products Ltd. regarding its complaint that the Utility has requested a security deposit for Woodland's three Prince George gas accounts. The Commission confirmed that the security deposit requirements contained in the approved Gas Tariff had been in place since 1988 (as Inland Natural Gas Co. Ltd.) (First Revision of Sheet No. 18) and that BC Gas applies the policy consistently throughout its service territory.

L-6-03 Centra Gas

Letter advising that the Commission would be prepared to remove the condition in CPCN No. C-15-02 with regard to the extension of the Utility's natural gas distribution system to Sooke, B.C. providing a Licence with satisfactory terms based on the January 28, 2003 Letter Agreement and the Commission's comments is filed by February 28, 2003.

L-7-03 Centra Gas

Letter confirming that Centra Gas has satisfied the condition set out in Article 1 of CPCN Order No. C-15-02 that required the Utility to have "the right to use the Galloping Goose right-of-way for the Pipeline over the long term under reasonable terms and conditions and usage fees".

L-8-03 BC Hydro

Letter to complainant advising that the Commission accepted BC Hydro's interpretation of Rate Schedule 1105 – Residential Dual Fuel Interruptible Service (Electric Plus), which states that electricity supply must be continuous for service under the Electric Plus Rate Schedule.

L-9-03 BC Gas

Letter requesting an evaluation of the cost impact and contract implications on the CustomerWorks contract if BC Gas were to allow multiple names on customer accounts.

L-10-03 Pope & Talbot

Letter responding to Pope & Talbot's Bypass Rate Application that applies for permission to build a 60 kV/4.16 kV substation in Grand Forks and move from Aquila Network's Rate Schedule 30 (Large General Service Primary) to Rate Schedule 31 (Large General Service – Transmission).

The Commission recommended that if the parties could not agree to a negotiated bypass rate that Pope & Talbot be allowed to construct and operate the proposed bypass facility under the condition that if backup is required, Pope & Talbot be required to pay all of the costs of backup to Aquila under terms agreed to by the parties in advance.

L-11-03 Office & Professional Employees' International Union, Local 378

Letter requesting the OPEIU to advise the Commission by April 4, 2003 of the impact that Order in Council No. 0219 has on its December 19, 2002 Application.

L-12-03 BC Gas

Letter advising that Commission staff would hold a Workshop for all interested parties to discuss the utility's February 28, 2003 "Commodity Unbundling and Customer Choice Report", which describes unbundling for both residential (RS-1) and commercial (RS-2 and RS-3) customers for November 1, 2004 using the Essential Services Model.

L-13-03 BC Hydro

Letter dismissing the complaint from The Owners, Strata Plan NES 2148 regarding Electric Tariff Supplement No. 31 (Field extension surcharge of 9.00¢/kWh). The Commission determined that BC Hydro appropriately applied its Electric Tariff surcharge to Strata Plan NES 2148 billings.

Publications

Copies of the following publications are available upon request or from the Commission's web site at *http://www.bcuc.com* :

- Utilities Commission Act, R.S.B.C. 1996, Ch. 473
- Introduction to the BC Utilities Commission - what it is, what it does, and why (pamphlet)
- Public Hearing Process - why we have public hearings and how to participate (pamphlet)
- Complaint Handling Procedures (pamphlet)
- Understanding Utility Regulation: A Participants' Guide to the British Columbia Utilities Commission
- Retail Markets Downstream of the Utility Meter Guidelines
- Integrated Resource Planning Guidelines
- Negotiated Settlement Procedures
- Certificate of Public Convenience and Necessity Filing Requirements
- Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Balance Guidelines

Copies of the following documents issued by the Commission are also available upon request or from the Commission's web site:

- Orders
- Decisions
- Regulatory Agendas
- Annual Reports
- Participant Assistance Cost Award Guidelines - Revised
- Service Plans
- Return on Common Equity

Commission Contacts

For further information about these items or the Commission's activities, please contact the Information Services Group at:

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Web Site

Internet users are invited to visit the Commission's web site at *http://www.bcuc.com.*

Glossary of Terms

allowance for funds used during construction (AFUDC)	The amount a regulated entity is allowed to earn to recover its cost of financing assets under construction. AFUDC is equal to the average cost of the construction work in process, times a financing rate which is usually equal to the entity's cost of capital rate. AFUDC is not recovered immediately through rates; it is included in the cost of the related assets and recovered in future periods through the depreciation charge.
allowed rate of return	The rate of return a regulated entity is allowed the opportunity to earn. When applied to the rate base, the allowed rate of return provides an amount equal to the cost of financing the investment required for regulated operations. The financing costs include both the cost of debt and the cost of equity.
alternative dispute resolution (ADR)	See "negotiated settlement process".
application for reconsideration	An application to have the Commission reconsider, vary, or rescind a decision or order previously issued.
burnertip rate	The rate charged for gas at the customer's meter, including the delivery charge, fixed monthly charge and gas commodity charge. It is usually calculated as an annual average rate based on typical annual consumption for the customer class.
capital cost	The fixed costs associated with the construction of an energy facility, including land and siting costs, material and labour costs, allowance for funds used during construction, and other applicable overhead charges.
cogeneration	The generation of electric power in conjunction with the use of steam in an industrial or space heating process, using waste heat from one process to drive the other. Cogeneration is more efficient compared to traditional thermal generating plants.
common carrier(s)	An energy transportation provider, typically a crude oil or natural gas pipeline which provides service on a non-discriminatory basis to all potential shippers.
cost of service	The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes and cost of capital. The cost of service is also known as "revenue requirements".
cost of service study	A study to determine the cost of service by class of service and/or customer. These studies are used to help determine how the revenue requirements are to be allocated among the rates for the various services/customers.
cross subsidization	Increasing the rates for one service or class of customers so the rates of another service or class of customers can be reduced below cost.

debt-equity ratio	The ratio of money borrowed by the utility to money invested in the utility by shareholders. There is a theoretical optimum for this for each utility.
deferral account	An account that records the deferral of a cost or revenue until a future date. A deferred asset account records a cost that would normally be expensed and recovered in the current period, but which is to be expensed or recovered in a future period. A deferred liability account records an amount recovered in the current period, to cover costs of providing service in a future period.
demand-side management (DSM)	Efforts to modify customer demand patterns by either increasing end-use energy efficiency or reducing fluctuations in energy demand.
distributed generation	Generation that is relatively small scale and located close to the final customer.
distribution system	The portion of an electric or natural gas transportation infrastructure that connects end-users to bulk production or transportation facilities.
energy losses	Energy lost during transportation from suppliers to end-users. Energy losses on a typical natural gas system are around 1 to 3 percent. Energy losses on a large electric system are around 5 to 8 percent.
export sales	Bulk sales of electricity or natural gas outside of British Columbia.
firm capacity	The amount of instantaneous energy production or transportation capacity that is available at a defined time.
firm energy	The amount of energy that is available over a defined period of time.
fixed cost	Costs associated with an energy production or transportation facility which must be paid whether the plant operates or not. Fixed costs generally include capital costs, contract demand charges and operating costs which are committed or unaffected by production levels.
gas cost reconciliation account (GCRA) **gas cost variance account (GCVA)**	A deferral account which accumulates the variance in actual gas costs from the actual gas revenue recovered in customer rates.
green power rates	Rates changed for electricity service from generators which do not pollute or damage the environment. Different groups define "green" power with various levels of restriction. For example, a run of the river hydro plant may be included while a new dam and reservoir may be excluded.
hydroelectric energy, hydroelectricity	Electric energy produced by water falling through a turbine generator. In British Columbia, hydroelectricity is the dominant form of electric energy production.

incentive regulation	Regulation which rewards utilities for cost savings or other actions which are desired by ratepayers.
independent power producers (IPPs)	Non-utility electric energy generators. Until the early 1970s, independent power producers were rare. With recent changes in utility technology and economics, they have become more common. Many issues relating to restructuring of the utility industry involve the role of independent power producers in a deregulated energy market.
information requests	Questions posed to the providers of evidence pertaining to the evidence they have filed for a hearing. Information requests and their responses are made prior to the hearing, in writing, and become evidence in the hearing. Information requests are also referred to as "interrogatories".
interim rate	A rate which is put in place until the regulator can determine the final rates. If the final rates are lower than the interim rates, customers are generally refunded their over contributions with interest for the period of time the interim rates existed.
interruptible energy, interruptible service	Energy flow which can be reduced or cut off on relatively short notice when needed by other customers. Generally, interruptible energy is sold by contract at a reduced price or without fixed charges to end-users, with specific terms and conditions governing interruptibility rights.
investor-owned utility	An electric or gas utility that is owned by private shareholders.
joule	A measure of energy or work done equal to a force of 1 newton applied through a distance of 1 metre. One gigajoule (one billion joules) is roughly equal to energy from 915 cubic feet of natural gas, 29 litres of gasoline, or 278 kWh of electricity.
kilowatt-hour	1,000 watt-hours.
load	The amount of energy required by end-users on a given portion of the system at a given time. Load originates primarily at customers' energy-consuming equipment.
load growth	Increase in the demand for energy.
load-resource balance	The point at which demand for energy exactly equals energy production.

local distribution company (LDC)	A utility (natural monopoly) that owns and operates the local delivery network for commodities such as electricity, natural gas and water. In a vertically integrated utility, local delivery is just one of several functions (e.g. B.C. Hydro). Thus, a LDC only exists when the delivery function has been vertically de-integrated (e.g. BC Gas).
market-based rates	Prices set freely in a competitive market, rather than prices based on costs of production.
megawatt (MW)	1,000 kilowatts, or 1,000,000 watts.
natural monopoly	An industry whose market output is produced at the lowest cost when production is concentrated in the hands of a single firm. The term utility is sometimes applied synonymously with natural monopoly.
negotiated settlement process (NSP)	A less formal process where the applicant, interested parties and Commission staff meet to review and attempt to negotiate a settlement on some or all aspects of an application. NSP is used to complement or as an alternative to the traditional regulatory process (e.g. oral public or written hearings) in an effort to save time and reduce the cost of utility regulation while achieving sound regulatory outcomes.
peaking gas	Gas which is stored or purchased under contracts which will allow delivery during the periods of highest demand.
performance-based rates	See "incentive regulation".
petajoule (PJ)	10^{15} or one quadrillion joules.
quasi-judicial	The powers and processes of a regulator which are similar to the courts.
rate base	The amount of investment in regulated operations on which a regulated entity is allowed to earn a return. It usually consists of the depreciated value of the plant in service required for regulated operations plus an allowance for working capital and deferred assets.
rate design	The methodology for apportioning the revenue requirement to the various class of utility customers.
rate rider	A specific charge on a customer's bill to recover a specific cost over a fixed period of time.
ratepayers	The customers of a utility.
rates	The prices at which regulated services are provided.

real time pricing (RTP)	Variable pricing of electricity in which the price depends on the cost or market value of providing electricity during each time segment. Applying RTP to electricity service results in customer rates that vary according to the specific utility costs at various times.
retail competition	Permitting end-use electricity customers to contract directly with electricity suppliers for their electricity commodity, while continuing to deal with transmission and distribution utilities for the commodity delivery. The energy commodity is generally sourced in a competitive marketplace.
return on equity (ROE)	The percentage return allowed for the invested equity of utility shareholders.
revenue requirements	See "cost of service".
self-generation	Generation of electricity by a customer for part or all of its own load requirements.
spot market	A real-time commodity market for immediate sale and delivery of energy products.
time-of-use rates	A rate structure that prices electricity at different rates, reflecting the changes in the utility's costs of providing electricity at different times of the day or year.
transmission grid, transportation grid, transmission system	An interconnected system of high voltage energy transportation lines and associated facilities used for bulk transfers of electricity. A high-pressure pipeline used for bulk transfers of natural gas is also referred to as a transmission system.
watt	The power required to do work at the rate of one joule per second.
watt-hour	One watt-hour is equal to 3,600 joules of energy.
wheeling	The service of delivering electricity across a transmission system for a third party.
wholesale markets	Wholesale electricity markets are comprised of transactions between buyers and sellers of bulk power at points on a high voltage transmission system.
wholesale rates	The unit prices charged for bulk energy services.